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In the Supreme Court of the United States

OCTOBER TERM, 1996

UNITED STATES OF AMERICA, PETITIONER

v.

EXXON CORPORATION AND SUBSIDIARIES

ON PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FEDERAL CIRCUIT

APPENDIX TO THE PETITION FOR A WRIT OF CERTIORARI

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APPENDIX A

UNITED STATES COURT OF APPEALS
FOR THE FEDERAL CIRCUIT

95-5116

EXXON CORPORATION AND SUBSIDIARIES,
PLAINTIFFS-APPELLANTS

v.

THE UNITED STATES,
DEFENDANT-APPELLEE

DECIDED: June 20, 1996

Before NEWMAN, *Circuit Judge*, SMITH, *Senior Circuit Judge*, and CLEVENGER, *Circuit Judge*.

CLEVENGER, *Circuit Judge*.

Invoking our jurisdiction under 28 U.S.C. § 1295 (a)(3) (1994), Exxon Corporation and its subsidiaries (Exxon) appeals from the decision by the Court of Federal Claims in *Exxon Corp. v. United States*, No. 89-660T (Fed. Cl., April 11, 1995). In that decision, the court held that Exxon's claimed depletion deduction was based on a legally insufficient representative price and, in any event, was unreasonable. As a result, the court rejected Exxon's claimed deduction and affirmed the proportionate profits method employed by the Commissioner of the Internal Rev-

enue Service (IRS) to calculate Exxon's allowable depletion deduction. We reverse and remand.

I

Exxon is a fully integrated producer of natural gas. As such, Exxon engages in all phases of the business, including exploration, extraction, processing, and transportation. In contrast, a nonintegrated producer sells natural gas immediately after extracting it, leaving to others the processing and distribution functions.

In order to support the major capital commitment required to develop its pipeline system, Exxon entered into several long-term natural gas sales contracts from 1953 to 1972, known as the Texas Industrial Commitments (TIC) contracts. Such contracts were common during this period because natural gas prices were stable and low. At the time these contracts were signed, the price terms were favorable to Exxon.

During the early 1970s, however, increased demand coupled with fears of an energy shortage led to a rapid escalation in the price of natural gas. The market price of natural gas doubled in 1973, and doubled again in 1974. In this seller's market, producers who were not already committed under long term contracts could practically write their own deals. In contrast, two thirds of Exxon's gas production was committed under the TIC contracts at an average delivery price of $0.23 per thousand cubic feet (Mcf).[1]

Although Exxon's sales were limited by these long-term contracts, Exxon believed its depletion deduction

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[1] This price included extraction, processing, and transportation by Exxon.

for tax purposes was not. For nonintegrated producers of natural gas, the depletion deduction is based on actual gross income, a known figure. Because the actual gross income of integrated producers includes revenue from transportation and processing, however, their depletion deduction is based on a constructive gross income derived from the average wellhead market price for similar gas. As explained in more detail below, the governing regulations refer to this average price as the representative market or field price (RMFP).

For its 1974 tax return, Exxon determined that the "field price" of similar natural gas was $0.36/Mcf. Because much of Exxon's gas production was committed under the TIC contracts at $0.23/Mcf, this "field price" exceeded Exxon's average actual sale price. Based upon a constructive gross income derived from this figure,[2] Exxon claimed depletion deductions totaling $170,094,205 with respect to the properties in issue.

On audit, the IRS determined that Exxon may not claim a depletion deduction based on an RMFP in excess of its actual gross income. Instead of using an RMFP, the IRS derived Exxon's depletion deduction based on Exxon's actual gross receipts from the TIC contracts. This methodology yielded a depletion deduction $11,105,698 lower than Exxon had claimed, thereby increasing Exxon's tax obligation for 1974 by $5,330,734. Exxon paid the tax and filed a refund suit in the Court of Federal Claims.

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[2] Both the "field price" and the RMFP represent the constructive gross income on a per unit basis. As a result, the constructive gross income equals the RMFP or "field price" multiplied by the volume of gas produced.

The Court of Federal Claims rejected the IRS' position that the RMFP, as a matter of law, can never exceed the taxpayer's actual gross income for purposes of calculating the depletion deduction. The court noted that nothing in the statute or regulations imposes such a limit. Because some of Exxon's data samples were improper, however, the court held that the RMFP proposed by Exxon was legally insufficient.

Moreover, the court decided that even if Exxon's figure was valid, the court had an independent duty to evaluate the reasonableness of an RMFP on a case-by-case basis. In the present case, the court decided it would be unreasonable to allow Exxon to use an RMFP in excess of its actual gross income. Accordingly, the court entered judgment in favor of the IRS.

II

On appeal, Exxon agrees that the Court of Federal Claims was correct in deciding that the pertinent statutes and regulations do not preclude, as a matter of law, an RMFP that exceeds the price actually charged for the gas sold. Exxon instead contends that the Court of Federal Claims erred in holding that Exxon had failed to prove a valid RMFP on the facts of this case. In addition, Exxon argues that the court erred in making an independent assessment of the reasonableness of Exxon's RMFP.

While the government defends the ultimate decision of the Court of Federal Claims, it argues that the court erred in holding that an RMFP may be used even if it exceeds the taxpayer's actual gross income. Alternatively, the government argues that the court correctly held that Exxon had failed to prove a valid

RMFP. The government also supports the court's determination that it has authority to conduct an independent assessment of the reasonableness of a particular RMFP, and that Exxon's RMFP is unreasonable when so assessed.

The opinion of the Court of Federal Claims explains at length and with admirable clarity the history of the depletion deduction in American tax law. We therefore need not repeat that background information and may proceed to the core issue of this appeal. The outcome of this case turns particularly on three statutes and one regulation. The Internal Revenue Code (IRC) provides that:

> In the case of mines, oil and gas wells, other natural deposits, and timber, there shall be allowed as a deduction in computing taxable income a reasonable allowance for depletion and for depreciation of improvements, according to the peculiar conditions in each case; such reasonable allowance in all cases to be made under regulations prescribed by the Secretary or his delegate.

I.R.C. § 611(a) (1974).[3]

Under section 613 of the IRC, the depletion allowance is limited to "50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion)." I.R.C. § 613(a). Moreover, the depletion allowance for oil or gas property is 22 percent of the "gross income from the property." I.R.C. § 613(a), (b).

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[3] Unless otherwise noted, all cites to the I.R.C. refer to the 1974 version.

There is no statutory definition of the term "gross income from the property." Instead, pursuant to the authority delegated to the Secretary I.R.C. § 611, he has defined its meaning as follows:

> In the case of oil and gas wells, "gross income from the property", as used in section 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is manufactured or converted into a refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or filed [sic, field] price [RMFP] of the oil or gas before conversion or transportation.

Treas. Reg. § 1.613-3(a) (1974).[4]

As the Court of Federal Claims recognized, the dispute in the present case focuses upon the application of this regulation in the context of depletion allowances for oil and gas.

III

As an initial matter, we address the government's contention that the statutes and regulations preclude, as a matter of law, the use of an RMFP that exceeds the taxpayer's actual gross income. The government first contends that the extant case law has already answered this question in its favor. Even if that is not so, the government argues that a proper inter-

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[4] Unless otherwise noted, all cites to treasury regulations refer to the 1974 versions of those regulations.

pretation of the statutory and regulatory provisions precludes such a result. We disagree on both bases.

A

We turn first to the government's argument founded upon case law. In support of this argument, the government cites *United States v. Henderson Clay Prods.*, 324 F.2d 7 (5th Cir. 1963), and *Panhandle Eastern Pipe Line Co. v. United States*, 408 F.2d 690 (Ct. Cl. 1969). These cases are best understood in the context of two other cases, *Hugoton Prod. Co. v. United States*, 315 F.2d 868 (Ct. Cl. 1963) (*Hugoton I*), and *Hugoton Prod. Co. v. United States*, 349 F.2d 418 (Ct. Cl. 1965) (*Hugoton II*). We do not find the precedent to be quite as dispositive as does the government, and conclude that no case has squarely addressed this issue.

In *Hugoton I*, the plaintiff was an integrated producer of natural gas who claimed that gross income for depletion purposes should be computed based on an RMFP.[5] *Hugoton I*, 315 F.2d at 870. The government, on the other hand, contended that there was no representative price for the plaintiff during the tax

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[5] The court referred to the plaintiff's approach as the "market comparison approach," which is equivalent to the RMFP approach. The RMFP approach is a means of disintegrating an integrated producer back into its separate extracting and processing/transporting entities. *Panhandle*, 324 F.2d at 15. Under the RMFP approach, the constructive gross income is that which the hypothetical extracting company would receive for sale of its products to its processing/transporting alter ego. *Id.*

years at issue and therefore a proportionate profits method should be used.[6]

The court decided that the RMFP approach must be used whenever a representative price can be established. *Id.* at 873. The court explained that although the Commissioner of the IRS could validly embody the proportionate profits method in regulations, he had chosen the RMFP approach and had defended its application when it produced larger revenues for the government. *Id.* at 872-73. Because the Commissioner did not include all contracts in his initial determination that there was no representative price, however, the court remanded for further findings. *Id.* at 877.

In the present case, Exxon's feet were held to the fire during the pre-1974 years when the RMFP was below Exxon's actual sales; at that time, Exxon accepted the RMFP approach although the proportionate profits approach would have been more favorable. During those years, the RMFP approach worked to the benefit of the government. Now, when the RMFP approach would work to the benefit of the taxpayer, the Commissioner asserts that he is permitted to use the proportionate profits approach.

The government insists that such a result is permissible based on prior case law. Between the times that *Hugoton I* and *Hugoton II* were decided the Fifth Circuit was faced with a similar case in the context of depletion deductions for clay mining. In

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[6] Under the proportionate profits method, the gross income from the property is calculated by taking the gross income from the sale of the processed gas and subtracting costs attributable to gathering and processing the gas. *Hugoton I*, 315 F.2d at 870.

Henderson Clay, the plaintiff was an integrated manufacturer that extracted ball clay and processed it into brick products, which it sold for $8.75 per ton. *Henderson Clay*, 324 F.2d at 9. Henderson, however, claimed a depletion deduction based on a representative price of $10.50 per ton, which was the price for shredded ball clay sold in the ceramics market. The Fifth Circuit stated:

> Tax law is law unto itself. There are no equities in tax law. And there is an area of permissible illogic in tax law. But when a taxpayer claims depletion on a fictitious gross income greatly in excess of its actual gross income, we find the claim highly indigestible.

Id. at 12.

The government relies heavily on this section for the proposition that *any* RMFP in excess of actual gross income is highly indigestible and therefore per se impermissible. We do not read *Henderson Clay* in such a sweeping manner.

The Fifth Circuit explicitly recognized that "on principle, it is irrelevant whether, in a particular case, the Cannelton rule [i.e. using an RMFP] will give a higher base or a lower base than the gross income from the finished product will yield." *Id.* at 12. On the facts of that particular case, however, the Fifth Circuit concluded that the $10.50 per ton price was not representative. *Id.* at 15.

Most importantly, the court noted that although Henderson claimed an RMFP based on the price for ball clay in the ceramics market, Henderson did not compete with nonintegrated clay producers in that

market. The higher price of ball clay sold in the ceramics market was due to advertising, management, and research costs incurred. *See Id.* at 10. As a young company, Henderson chose not to compete in this market because it could not afford the associated costs. *Id.* As a result, the court concluded that the $10.50 per ton price "in no way represents the depletion of the taxpayer's clay resources and in no way represents the price which a non-integrated brick manufacturer would pay for clay with which to make brick." *Id.* at 15.

In sum, the Fifth Circuit in *Henderson Clay* did not impose a cap on the RMFP. Instead, it decided that the proposed price was not representative of the price Henderson could have obtained for its ball clay.

We are not the first court to interpret *Henderson Clay* in this manner. As explained above, *Henderson Clay* was decided between *Hugoton I and Hugoton II*. On remand after *Hugoton I*, the plaintiff was unhappy with the resulting RMFP and again appealed to the Court of Claims. This time, the plaintiff contended that the RMFP should be rejected because it was not representative and that a proportionate profits method should be applied as was the case in *Henderson Clay*. *Hugoton II*, 349 F.2d at 424-25.

In support of its argument, the plaintiff hypothesized two integrated gas producers, A and B. A obtains $0.15/Mcf for its gas, B obtains $0.05/MCF, and the RMFP is approximately $0.10/Mcf. *Id.* at 424. The plaintiff explained that "in the case of producer B the hypothetical gross income in each of the taxable years even though based on actual sales of other producers at the wellhead would exceed B's

actual gross income from gathering and processing natural gas." *Id.*

The court "reject[ed] plaintiff's somewhat simplified reasoning that the Fifth Circuit decision resulted in a sweeping rejection of the market comparison method simply because, on the facts presented, it produced results not economically representative of the taxpayer's integrated business." *Id.* at 425. Instead, the court noted that the $10.50 per ton price in *Henderson Clay* was rejected as nonrepresentative merely because there was no competition between Henderson and the other clay miners. *Id.* at 426. *Hugoton II*, it should be noted, is binding precedent on the decision of this case, and we thus are not at liberty to reject the interpretation given to *Henderson* in *Hugoton II*. *See South Corp. v. United States*, 690 F.2d 1368, 1370 (Fed. Cir. 1982) (in banc).

Finally, the government cites *Panhandle* in support of its argument. In *Panhandle*, the taxpayer entered into a contract with Consumer Power Company to sell gas from fourteen wells at a price of $0.325/Mcf. *Panhandle*, 408 F.2d at 710. The delivery point for part of the production from one well, the McPherson No. 1—35 well, was near the wellhead. The balance of the production was transported from the wellhead for delivery to Consumers Power Company at locations from thirty to forty miles away. *Id.* at 710-711.

The court determined that the sale price of $0.325/Mcf at McPherson No. 1—35 was a valid market price for wellhead sales. Nevertheless, the court determined that under the facts of the case, such a price was not representative of the price that Panhandle could realize for sales at the wellhead. *See id.* at 716. The contract provided that Panhandle

would receive $0.325/MCF whether it sold it at the wellhead or after transportation. Given the undisputed fact that the cost of transportation was $0.325/Mcf, the court inferred that the $0.325/Mcf figure represented a blended price to cover all gas sold under the contract. *Id.* at 716-17. Had the gas been priced separately depending on its delivery point, it presumably would have sold for a higher price after transportation and for a lower price at the wellhead. *See id.* Therefore, the court concluded that $0.325/Mcf did not represent the wellhead price.

In sum, the cases cited by the government involve situations where the courts decided that the proffered market price was not representative because it included transportation or processing (e.g. advertising) costs. In contrast, the RMFP in the present case exceeds actual gross receipts because of the effects of changing market conditions. Our review of the pertinent case law reveals that no court has explicitly stated that such an RMFP is impermissible.

B

The government next argues that even if the extant case law is not dispositive, the statutes and regulation preclude an RMFP that exceeds the taxpayer's actual gross income. We begin our analysis with the language of the relevant statutory and regulatory sections, as they read in 1974. *See Johns-Manville Corp. v. United States*, 855 F.2d 1556, 1559 (Fed. Cir. 1988), *cert. denied*, 489 U.S. 1066 (1989).

Exxon contends that a literal reading of Treas. Reg. § 1.613-3(a) requires the use of an RMFP whenever, as is the case here, the natural gas has been processed and transported away from the prem-

ises prior to sale. Moreover, Exxon argues, because the RMFP is a constructed value, actual gross income is irrelevant. We agree that the plain language of the tax scheme supports Exxon's contention.

Section 611 obligates the Secretary to promulgate regulations that provide for a reasonable allowance. Pursuant to this delegation, the Secretary promulgated only one method of calculating the depletion allowance for integrated natural gas producers—the RMFP. Treas. Reg. § 1.613-3(a). Notably, this regulation contains no language that expressly limits the RMFP to actual gross income.[7]

This lack of an express limit on the RMFP takes on added importance because it is clear that the Secretary was aware of the possibility that the field price could exceed actual revenues. In the area of hard minerals, the Secretary promulgated a regulation creating a rebuttable presumption that such a field price is not representative. *See* Treas. Reg. § 1.613-4 (c)(6). Such a limitation is strikingly absent, however, from the oil and gas regulation.

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[7] Indeed, the only express limitation on the RMFP is found in section 613 of the IRC, which limits the depletion allowance to "50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion)." I.R.C. § 613 (1974). This independent limitation, however, does not mean that the RMFP cannot exceed actual gross income. Instead, it means that 22 percent of the RMFP cannot exceed 50 per cent of the actual gross income. *See id.*

Suppose, for example, that actual gross income was $100,000 and the RMFP was $200,000. The depletion allowance would then be 22 per cent of $200,000, or $44,000. Because this allowance does not exceed 50 per cent of the taxable income, $50,000, it would not violate any statutory restrictions; and yet the RMFP is clearly in excess of the actual gross income.

We note that pursuant to the broad authority delegated to him, the Secretary can amend Treas. Reg. § 1.613-3(a) if he so desires to limit the RMFP to actual gross income. *See Hugoton II*, 349 F.2d at 430. In fact, the Secretary at one time considered making such an amendment, but that proposal was ultimately withdrawn. *See* 36 Fed. Reg. 19256 (1971); 33 Fed. Reg. 10700 (1968). Until the Secretary imposes such a cap in the oil and gas area, we believe it is not within our judicial powers to legislate in his stead. *See Hugoton II*, 349 F.2d at 430.

We nonetheless are mindful that a regulatory provision must not be read in a vacuum, but instead in light of the entire law and its object and policy. *See John Mancock Mut. Life Ins. Co. v. Harris Trust & Savings Bank*, 114 S. Ct. 517, 523 (1993); *Trustees of Indiana Univ. v. United States*, 618 F.2d 736, 739 (Ct. Cl. 1890). We therefore must ensure that our interpretation is consistent with the statutory objective.

The Revenue Act of 1918 allowed oil and gas producers a "discovery depletion" deduction based upon the fair market value of the property on the date of discovery of the well. Revenue Act of 1918, Pub. L. No. 65-254, ch. 18, § 234(a)(9), 40 Stat. 1057, 1078-79 (1919). When enacting this statute, Congress feared that taxpayers would use the depletion deduction to offset profits derived from separate and distinct lines of business. S. Rep. No. 275, 67th Cong., 1st Sess. 14-15 (1921). To prevent such abuse, Congress provided that the depletion deduction shall not exceed the net income from the property, computed without allowance for depletion. Revenue Act of 1921, ch. 136, § 234(a)(9), 42 Stat. 227, 256 (1921). In

1924, this restriction was further tightened to cap the depletion deduction at fifty percent of the taxpayer's net income from the property. Revenue Act of 1924, ch. 234, § 204(c), 43 Stat. 253, 260 (1924).

Calculating the fair market value on the date of discovery of the well, however, proved to be difficult to administer and created uncertainty. In response, Congress simplified administration of the deduction by basing it upon a percentage of the taxpayer's gross income from the property. Revenue Act of 1926, ch. 27, § 204(c)(2), 44 Stat. 9, 16 (1926). Because Congress did not define the meaning of gross income from the property, several integrated producers claimed a deduction based upon gross receipts after processing and distribution. In order to ensure that integrated producers did not achieve a greater tax deduction than their nonintegrated competitors, *see Hugoton II*, 349 F.2d at 425, Treasury Regulation 74, Art. 221(i) was promulgated stating:

> If the oil and gas are not sold on the property but are manufactured or converted into a refined product or are transported from the property prior to sale, then the gross income shall be assumed to be equivalent to the market or field price of the oil and gas before conversion or transportation.

Treas. Reg. 74, Art. 221(i) (1931 ed.). This regulation is substantially similar to Treas. Reg. § 1.613-3(a) at issue in this case.

The legislative history of these provisions therefore reveals two primary limitations. First, the deduction should not allow a taxpayer to offset profits earned from a separate line of business. As explained above,

this does not limit the RMFP to actual gross income. Second, integrated manufacturers should not be allowed to include in their "gross income from the property" any value that was added to the gas after extraction, such as by processing or transportation. *See Hugoton I*, 315 F.2d at 869. Several courts have referred to this second objective as requiring that an integrated producer not receive a competitive tax advantage over nonintegrated producers.

The government seizes upon this second objective and argues it would be frustrated if Exxon is allowed to use an RMFP in excess of its actual gross receipts. The government notes that some nonintegrated producers entered into long term contracts at low prices just as did Exxon; because they are nonintegrated, however, their depletion deduction would be limited to their low contractual prices rather than a higher deduction based on an RMFP. In other words, the government argues that the statutory objective requires that integrated producers in long term contracts receive no tax advantage over nonintegrated producers in long term contracts. We disagree.

Treas. Reg. § 1.613-3(a) and its predecessors were designed to ensure that integrated producers did not include in their gross income calculation any value added by their processing and transportation components. *See Panhandle*, 408 F.2d at 700. The RMFP in the present case exceeds the actual gross income based on market forces and not based on downstream processing. While the legislative history addresses the effects of downstream processing, it is silent as to changes in market conditions. Contrary to the government's argument, therefore, we do not violate this

statutory objective by refusing to limit the RMFP to actual gross income.

In sum, the legislative history does not reveal an intent to limit the RMFP to actual gross receipts. Instead, the legislative history reveals that the RMFP is employed as an inexact, simplified means of calculating an integrated producer's depletion deduction.[8] We therefore agree with the Court of Federal Claims that neither prior case law, nor the language of the statute, nor its legislative history limits an otherwise valid RMFP to actual gross income.

IV

After deciding that the RMFP is not limited to actual gross income, the Court of Federal Claims nonetheless ruled against Exxon. The court decided that, based on the facts of this case, Exxon had failed to prove a valid RMFP.

At trial, Exxon's pricing expert stated that in 1974, the RMFP for natural gas was $0.41/Mcf. In support of this proffered RMFP, Exxon submitted data concerning 2,228 sales. These sales allegedly represented over ninety percent of the wellhead sales of comparable unprocessed gas in Exxon's market area. The court determined that many of these sales should not have been included in the RMFP because they included either dehydration or transportation costs. As to the remaining sales, the court professed that:

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[8] On average, the RMFP "will tend to equalize the depletion allowance as between integrated and nonintegrated producers." *Hugoton I*, 315 F.2d at 876. Any nonintegrated producers locked into long term contracts will be included in the RMFP calculus and will tend to lower the RMFP. On the other hand, nonintegrated producers selling at current market prices will tend to raise the RMFP.

> The court is unable to extract from the 2,228 sales proffered by Exxon those sales clearly established to be gas sales in the immediate vicinity of the wells. The vastness of Exxon's sample hindered rather than helped the court determine the accuracy of the proposed RMFP.

Exxon first contends that all of the sales included in its $0.41/Mcf RMFP were proper. Exxon next contends that even if some sales should have been excluded, the court erred by failing to determine an RMFP based on the remaining sales. We disagree with Exxon's first argument, but agree with the second.

A

As the Court of Federal Claims recognized, calculation of the RMFP is a difficult and sometimes onerous task. This difficulty is exacerbated by the fact that the Secretary has declined to promulgate regulations which could provide guidance to taxpayers and the courts. In the absence of such guidance, both the taxpayers and the courts must formulate and evaluate the RMFP based on a common law approach that looks to prior adjudications of depletion allowances. Although such an approach does not create a unitary test for formulating an RMFP, several general principles may be discerned.

In reviewing prior case law for guidance, we must remember that the fundamental goal of the calculation is to arrive at a price that is *representative* of the price which would be realized by nonintegrated producers. Accordingly, prior cases have stated that the RMFP of gas is calculated as the weighted average price of wellhead sales of comparable gas in the

taxpayer's market area. *Panhandle*, 408 F.2d at 703; *Hugoton I*, 315 F.2d at 877. In making this calculation, prior cases have emphasized the value in using a large sample size of transactions because the large sample size "should provide greater assurance that the price derived is in fact representative." *Hugoton I*, 315 F.2d at 877. The sample set, however, must be limited to wellhead sales and may not include sales in which the gas was processed or transported by the taxpayer. *Panhandle*, 408 F.2d at 716. Finally, the RMFP should be calculated based on all wellhead sales for the given tax year at issue, regardless of their contract date. *Hugoton I*, 315 F.2d at 871.

B

In reliance on this precedent, Exxon compiled data of 2,228 comparable sales. Based on language in *Panhandle*, Exxon derived most of this data from annual reports filed by natural gas pipelines with the Federal Power Commission (FPC) and the Gas Utilities Division (GUD) of the Texas Railroad Commission. *See Panhandle*, 408 F.2d at 704-05 ("[i]t would be better, in any future litigation of this same kind, if the parties relied solely upon information contained in said [FPC] forms"). Exxon also confirmed 1,164 of these transactions by reviewing the actual contracts of a single pipeline company. As a result, Exxon arrived at an RMFP of $0.41/Mcf.

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As an initial matter, the government argues that *Panhandle* is limited to situations where the two parties agree on which transactions should be included

in the RMFP calculation. Where the parties disagree, the government argues, *Panhandle* does not apply and the taxpayer must support its RMFP calculation with actual contracts. We disagree with this reading of *Panhandle*.

Panhandle does not resolve any dispute as to which transactions should be included in the RMFP calculations. Instead, *Panhandle* merely articulates the form of proof that will suffice to represent those transactions. When read in context, *Panhandle* emits a palpable sense for the need to accommodate the burdens inherent in calculating the RMFP in depletion cases:

> It cannot be seriously disputed that it is impractical to go behind the Forms 2 in a comprehensive manner because this would require an unduly time-consuming and burdensome examination of all purchase contracts listed in the gas purchase sections of the forms. In this connection, it should be noted that during the trial the attorneys for both parties stated that if they had gone behind the forms to any greater extent than this [sic] had been done by defendant, "[w]e would never have tried this case."

Panhandle, 408 F.2d at 704.

Based on its context, we read *Panhandle* as creating a rebuttable presumption that filed annual reports constitute prima facie proof of the transactions they represent. Nonetheless, the parties remain free to rebut this presumption with proof that the forms conflict with the underlying contracts. Moreover, the parties remain free to disagree as to which FPC transactions should be included in the RMFP calculation.

In accordance with this approach, the Court of Federal Claims considered the transactions represented by the FPC Form 2 but rejected some which involved sale of gas after transportation. The court noted that the FPC Form 2 divides gas purchases by pipelines into two categories. Account 800 purchases are defined as wellhead purchases "where only the utility's [the purchaser's] facilities are used in bringing the gas from the well head into the utility's natural gas system." 18 C.F.R. part 201, account 800 (1974). In contrast, Account 801 purchases are defined as field line purchases "where facilities of the vendor or others are used in bringing the gas from the well head to the point of entry into the utility's natural gas system." 18 C.F.R. part 201, account 801 (1974). As the court explained, "[t]he distinction is that in Account 800 sales the *purchaser* transports the gas away from the wellhead; whereas in Account 801 sales, the *producer* transports the gas away from the wellhead."

Exxon's data included both Account 800 and Account 801 sales. Because Account 801 sales include value added by transportation and because Exxon's study did not cleanse the Account 801 sales by subtracting the value added by transportation, we agree with the Court of Federal Claims that such sales should not play a role in the RMFP calculus in this case. Such transactions, however, should not necessarily be excluded altogether, especially in light of the goal of maximizing the number of transactions included.[9] Instead, it would be preferable for the

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[9] In the present case, the evidence indicates that 723 of the 2,228 transactions represented Account 800 sales. Thus,

taxpayer to cure these tainted transactions by subtracting the transportation cost from the sale price. *Cf. Panhandle*, 408 F.2d at 718 (arriving at a price of $0.29/Mcf by subtracting $0.035 as transportation costs from the sale price of $0.325).

In addition to Account 801 sales, Exxon also included in its calculation transactions where the gas was dehydrated and compressed prior to sale. This approach is reasonable, Exxon contends, because dehydration is an ordinary production activity as opposed to a manufacturing activity. In fact, Exxon asserts that dehydration by the producer is the rule rather than the exception; and the cost of dehydration, varying from $0.0025/Mcf to $0.005/Mcf, is quite small. Because it is easier and more economical for the producer to perform this task, the industry views dehydration as the producer's responsibility. Exxon's study, however, did not reduce the price of each sale by the applicable dehydration cost amount.

The Court of Federal Claims rejected Exxon's contention that dehydration sales should be included in the RMFP calculus. The court agreed with the government's expert who testified that ordinary production methods are purely mechanical in nature whereas dehydration requires a chemical reaction. In addition, the court noted that some pipelines purchased gas prior to dehydration. Finally, the court recognized that excluding dehydration was consistent with the prior case law which considered as comparable sales only those delivered to the purchaser at the wellhead or separater. *Hugoton I*, 315 F.2d at 869; *Panhandle*, 408 F.2d at 704; *Shamrock Oil & Gas Corp. v. Commissioner*, 35 T.C. 979, 1036-37 (1961), *aff'd*,

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eliminating Account 801 sales altogether would reduce the sample set by 68 per cent.

346 F.2d 377 (5th Cir.), *cert. denied*, 382 U.S. 892 (1965). Based on the evidence, the court's decision to exclude sales after dehydration from the RMFP calculus in this case is not clearly erroneous. As with the transportation costs, however, we note that it would be preferable, if possible, for the taxpayer to subtract the dehydration costs from the transactions rather than force the elimination of those transactions altogether.

3

Finally, Exxon contends that even if the Court of Federal Claims properly excluded certain transactions, the court failed in its obligation to determine an RMFP based on the remaining transactions. Exxon notes that in calculating its RMFP, Exxon was forced to make numerous decisions on issues such as market area, comparability, and which transactions to include. Given the nebulous character of these issues, Exxon explains, it was not implausible that the court would disagree with one or more of its decisions. To accommodate this possibility, Exxon's price study provided the data in a manner that allowed the court to use only some of the transactions.

The government does not argue that the remaining sales constituted an insufficient sample from which an RMFP could be calculated. *See Hugoton II*, 349 F.2d at 420 (indicating that a sample containing twenty contracts is sufficient); *cf. Panhandle*, 408 F.2d at 714-15 (suggesting that a sample containing only one transaction could be used to calculate the RMFP). Instead, the government argues that the remaining sales cannot be used to calculate an RMFP because: (1) Exxon's sales data is not presented in a manner that allows the isolation of wellhead sales; and (2)

the Account 800 sales reported on the FPC forms may not have been wellhead sales. We disagree with the government's arguments.

The government first contends that Exxon's data cannot be parsed to reveal pre-dehydration Account 800 sales. On the record before us, however, it appears that Exxon's study contains a list and description of each transaction included in its RMFP calculation. For example, Exhibit 45 is a list of pre-dehydration sales; and Exhibit 29 is a list of pre-compression sales, with the first three pages limited to Account 800 sales. The overlap between these two should yield pre-dehydration, pre-compression, Account 800 sales. Therefore, the data presented by Exxon can be parsed to reveal pre-hydration Account 800 sales.

Next, the government contends that Account 800 transactions should not be used because they may contain field line purchases as well as wellhead purchases. In support, the government points to a "note" appearing under Account 800 which states that "[i]f gas purchases are made under one contract covering both well head and field line purchases and such amounts are not readily separable, the utility may classify such purchases according to predominant source or according to a reasonable estimate." 18 C.F.R. Part 201, Account 800 (1974). As explained above, however, we presume that the FPC forms are representative of their underlying transactions. Either party may rebut this presumption with proof that some of the transactions listed in the forms are not representative. *Cf. Panhandle*, 408 F.2d at 704 (allowing an adjustment because gas purchased at the wellhead was erroneously listed as non-wellhead sales). In the

present case, however, the government has made no showing of proof to rebut the FPC transactions which meet the Court of Federal Claims' criteria. Therefore, in the present case, the pre-dehydration transactions listed in Account 800 may properly be used to calculate the RMFP.

In sum, the Court of Federal Claims properly rejected certain transactions in Exxon's study because they did not represent wellhead sales. The court erred, however, by truncating its RMFP analysis thus not reaching the issue of whether Exxon's study contained any valid transactions from which an RMFP could be determined. Nonetheless, we need not remand this case for calculation of the RMFP because the undisputed evidence of record supports an RMFP in the amount of $0.39/Mcf.[10]

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[10] The first three pages of Exhibit 29 list pre-compression Account 800 sales. [JA at 7021-7023] Exhibit 45 lists, in decreasing order of volume, all transactions in which the seller does not dehydrate the gas. [JA at 7259-7266] Those transactions which appear on both of these lists satisfy the Court of Federal Claims' criteria for wellhead sales. These qualifying transactions are summarized below, in decreasing order of volume purchased:

Purchaser	Volume (in Mcf)	Price per Mcf
Lovaca Gathering Company	9,330,442	$0.16
Lovaca Gathering Company	7,515,106	$0.16
Delhi Gas Pipeline Corp.	2,544,020	$0.71
Delhi Gas Pipeline Corp.	2,073,461	$0.76
Houston Pipe Line Company	1,325,003	$0.97
Houston Pipe Line Company	755,460	$0.87
Houston Pipe Line Company	752,259	$0.17
Houston Pipe Line Company	682,373	$1.02
Houston Pipe Line Company	446,481	$0.91

(Continued)

V

The Court of Federal Claims stated that even if Exxon had proven its proffered RMFP, the court had authority to conduct an independent assessment of its reasonableness. While recognizing that the RMFP is not limited to actual gross income, the Court of Federal Claims decided that "the test, it seems to the court, is not whether the RMFP exceeds or is below the actual sales price of the gas but rather whether the RMFP is *reasonable* under the circumstances." In support, the court relied on two factors. First, the statute provides for a "reasonable allow-

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[10] (Continued)

Purchaser	Volume (in Mcf)	Price per Mcf
Delhi Gas Pipeline Corp.	416,520	$0.13
Lovaca Gathering Company	401,636	$1.16
Houston Pipe Line Company	378,131	$1.38
Lovaca Gathering Company	314,700	$0.19
Lovaca Gathering Company	305,128	$0.46
Bi Stone Fuel Company	298,046	$0.49
Lovaca Gathering Company	274,657	$0.24
Houston Pipe Line Company	203,680	$1.18
Arkansas Louisiana Gas Co.	165,326	$0.12
Houston Pipe Line Company	149,239	$0.54
Houston Pipe Line Company	132,599	$0.30
Houston Pipe Line Company	96,654	$0.85
Lovaca Gathering Company	60,750	$1.15
Lovaca Gathering Company	35,220	$0.35
Lovaca Gathering Company	33,414	$0.35

The total price for these transactions is approximately $11,260,653. This is derived by multiplying the volume of each transaction by the price for that transaction, and summing the resulting figures for all transactions. The volume weighted average price is derived by dividing this total price of $11,260,653 by the total volume of 28,690,351 Mcf. This results in a volume weighted average price of $0.39/Mcf.

ance for depletion . . . according to the peculiar conditions in each case." I.R.C. § 611(a). Second, the court found support in prior case law. We disagree that the court's approach is appropriate.

Section 611 indeed provides for "a reasonable allowance for depletion." I.R.C. § 611(a). Importantly, however, the statute also provides that "such reasonable allowance in all cases [is] to be made under regulations prescribed by the Secretary or his delegate." *Id.* We do not read this broad directive as allowing the courts to adjudicate the reasonableness of an allowance on a case-by-case basis. Instead, the statute directs the Secretary to promulgate regulations which will apply *in all cases* to yield a reasonable allowance. Pursuant to this directive, the Secretary has promulgated Treas. Reg. § 1.613-3(a), which remains of unquestioned validity. *See Hugoton I*, 315 F.2d at 871. Because Congress has charged the Secretary with the task of promulgating regulations which yield a reasonable allowance, we hold that a depletion allowance pursuant to Treas. Reg. § 1.613-3(a) is per se reasonable, absent a challenge to the regulation itself.

Our reasoning is similar to that of the United States Supreme Court in *Commissioner v. Portland Cement Co. of Utah*, 450 U.S. 156 (1981), a case which also involved Treasury Regulations for depletion allowances. The Court explained its basis for applying the Treasury Regulations at issue in that case as follows:

> These regulations command our respect, for Congress has delegated to the Secretary of the Treasury, not to this Court, the task "of administering the tax laws of the Nation." . . . Treasury Regu-

> lations "must be sustained unless unreasonable and plainly inconsistent with the revenue statutes." Indeed, our customary deference to Treasury Regulations is particularly appropriate in this case, for the Court previously has recognized the necessity of a "broad rule-making delegation" of authority in the area of depletion. . . .

Id. at 169 (citations omitted). This case demonstrates that the Secretary is charged with promulgating regulations and our scope of review is limited to the reasonableness of the regulations and not the reasonableness of any individual allowance.

In support for its approach, the Court of Federal Claims also relied on the statutory language that the reasonable allowance be made "according to the peculiar conditions in each case." I.R.C. § 611(a). This, the court stated, supported a case-by-case inquiry into the reasonableness of a particular allowance. This interpretation, however, has been rejected by the Supreme Court. The Court has explicitly explained that "[r]ead in context, 'in each case' refers to the different types of depletable resource [e.g., mines, oil and gas, timber, etc.], not to individual taxpayers." *Portland Cement*, 450 U.S. at 171 n.20. Therefore, the statutory language does not support the Court of Federal Claim's case-by-case reasonableness inquiry.

The Court of Federal Claims also stated that *Panhandle* and *Henderson Clay* stand for the proposition that the RMFP must be reasonable. We disagree. As explained above, in each of those cases, the court decided that the proffered price was not representative. *See Panhandle*, 408 F.2d at 716; *Henderson Clay*,

324 F.2d at 15. In other words, a *representative* market or field price, i.e., RMFP, had not been established. If an RMFP is proven, however, nothing in prior case law requires the court to conduct an independent reasonableness inquiry.[11]

In sum, neither the statutory language nor prior case law allows, let alone requires, the Court of Federal Claims to conduct an independent reasonableness inquiry once an RMFP has been established.

VI

We conclude that prior case law does not preclude an RMFP that exceeds actual gross receipts. This is consistent with the statutory scheme which delegates to the Secretary of the Treasury the authority to promulgate regulations that provide for a reasonable depletion allowance. Pursuant to this authority, the Secretary promulgated Treas. Reg. § 1.613-3(a), which is the only regulation that applies to integrated natural gas producers. Although the Court of Federal Claims was correct in deciding that there is no express limit on the RMFP, we conclude that the court erred by engaging in a reasonableness inquiry. If an RMFP is established, it must govern.

Finally, although the court properly rejected certain transactions included in Exxon's RMFP calculation, the court erred by failing to conclude that Exxon's study contained qualifying transactions from

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[11] Whether a price is representative depends simply on an objective evaluation of the price being obtained by nonintegrated producers. In contrast, the determination of whether a price is reasonable can depend on numerous factors including notions of fairness, the taxpayer's profit margin, etc.

which a valid RMFP could be calculated. The decision of the Court of Federal Claims is therefore reversed. The record supports an RMFP of $0.39/Mcf, and Exxon is entitled to use that figure in calculating its depletion deduction for the period in question. Because we conclude that Exxon is entitled to an RMFP of $0.39/Mcf, rather than of $0.36/Mcf "field price" as originally claimed, we remand the case to the Court of Federal Claims for entry of a final decision consistent with our conclusion.

REVERSE AND REMAND

UNITED STATES COURT OF APPEALS
FOR THE FEDERAL CIRCUIT

Appeal No. 95-5116

EXXON CORP.

v.

UNITED STATES

July 10, 1996

SECOND ERRATA

Decided: June 20, 1996 Precedential opinion

Please make the following correction:

Page 13: Delete footnote 7.

UNITED STATES COURT OF APPEALS
FOR THE FEDERAL CIRCUIT

Appeal No. 95-5116

EXXON CORPORATION AND SUBSIDIARIES

v.

THE UNITED STATES

June 20, 1996

ERRATA

Decided: June 20, 1996 Precedential Opinion

Please make the following correction:

Page 25, Footnote 10, delete bold bracketed citations

APPENDIX B

IN THE UNITED STATES COURT
OF FEDERAL CLAIMS

No. 660-89T

(Filed: June 29, 1993)

EXXON CORPORATION ET AL., PLAINTIFFS

v.

THE UNITED STATES, DEFENDANT

ORDER

LYDON, Senior Judge:

The plaintiffs in this action are Exxon and other subsidiary corporations, who for convenience will be referred to collectively as Exxon. Exxon seeks to recover income taxes paid after deficiencies had been assessed by the Commissioner of Internal Revenue relating to the 1974 tax year. The issue before the court is the amount of the percentage depletion deduction that plaintiff should be allowed to deduct on its 1974 tax return. Defendant has moved for judgment on the pleadings and for summary judgment. Having considered the parties' submissions and having heard oral argument, the court denies both motions.

I

Exxon Corporation is in the business of exploring for and producing crude oil and natural gas and refining, transporting, buying, and selling petroleum and petroleum products. Because Exxon has the capacity to transport its raw natural gas away from its wells through its own pipeline so it can be processed before sale, it is considered an "integrated producer". One must keep in mind the contextual use of the term "natural gas" in this order. The price or value of the "natural gas" at issue in this litigation is the price of the raw product that emerges from the ground, commonly referred to as the wellhead price. At times, the term "natural gas" is used to refer to the finished state of the product after refining, the value of which cannot form the basis, by itself, of any depletion deduction allowance unless modified to eliminate the increase in value caused by processing after it appears at the wellhead.

A. Exxon's Gas Production in Texas During 1974

During 1974, the taxable year in issue, Exxon owned economic interests in 504 mineral properties located in 63 oil and gas fields in east and south Texas.[1] Raw natural gas was produced at each of these properties and, in most cases, transported away

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[1] Exxon owned its economic interests in most of these properties by way of mineral leases. These leases typically contained provisions requiring Exxon to pay the lessors, as royalty, from one-eighth to one-sixth of the value of the oil and gas it produced. Exxon owned the remaining economic interests by way of mineral fee.

from each producing property prior to sale.[2] The natural gas produced from wells on each of these properties was, in most instances, first passed through an on-site gravity separator to separate the raw gas from sand, water, condensates (heavy hydrocarbons), and crude oil. Raw gas that was relatively rich in liquefiable hydrocarbons, which characterizes most of the gas in this case, generally was gathered in the field and transported by pipeline to one of eight natural gas processing plants operated by Exxon.[3] At the plants, the bulk of the liquefiable hydrocarbons was removed from the gas and manufactured or converted into ethane, propane, butanes, and natural gasoline, which were further processed or marketed as natural gas liquids. What remained after the removal of the liquefiable hydrocarbons was "residue gas", gas that consisted largely of methane, which was processed to meet industrial use or commercial pipeline specifications. Raw gas that was not relatively rich in liquefiable hydrocarbons was not processed at

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[2] Natural gas has two primary commercial uses, as a gaseous fuel and as a chemical feedstock. It is often economically attractive to process raw natural gas in order to separate the lightest component, methane, for use as a gaseous fuel from the heavier compounds, which have more valuable uses as liquid fuels or a chemical feedstock.

[3] Prior to sale, raw natural gas, a variable mixture of different hydrocarbon compounds in various proportions, is usually conditioned (to make it suitable for transfer through the pipeline) and processed (to make it suitable for separate and distinct requirements of customers). The gas Exxon transported in the pipeline system that serves these properties is almost entirely methane, carefully conditioned to meet stringent pipeline operating specifications.

a natural gas processing plant.[4] On occasion, a portion of the produced gas may be returned to the reservoir to increase total hydrocarbon recovery.

Some of the finished products made at the plants were offered to customers for sale in the ordinary course of business, such as the heavier natural gas liquids (ethane, butane, etc.) it sold to third parties

[4] In 1974, the eight Exxon processing plants converted raw natural gas into a number of compounds as follows:

1974 Plant Products by Plant (Bbls)

Gas Plant	C1/C2	C3	iC4/nC4	iC5/nC5	Heavier
King Ranch	341M	178M	122M	188M	0
Katy	5.7M	2.2M	1.1M	2.5M	0
Lovell Lake	100K	119K	81K	0	73.5K
Pledged	0	0	112K	0	758K
East Texas	253K	532K	477K	0	332K
Hawkins	72K	915K	1M	0	791K
Anahuac	715K	592K	343K	370K	0
Clear Lake	895K	598K	319K	301K	0

(M = million Bbls; K = thousands Bbls.)

Hydrocarbon Name	Abbreviated symbol commonly used in gas processing
Methane	C1
Ethane	C2
Propane	C3
Iso-butane	iC4
Normal butane	nC4
Isopentane	iC5
Normal Pentane	nC5
Hexane	C6
Heptane	C7
Octane	C8
Nonane	C9
Decane	C10

for money consideration at arm's-length at the plant. Some finished products were transported to other Exxon facilities for Exxon's own use as an energy source and as chemical feedstocks. Unlike the sales to third parties, these intracompany transactions generated no identifiable "purchase price". Thus, Exxon used "constructive prices," which Exxon called "Exxon Posted Prices," for those gas products transferred from its gas processing plants to its refineries and pipelines. For methane, processed and conditioned to meet pipeline specifications and delivered to Exxon's own pipeline, the constructive prices were called "Exxon Field Prices."

Because of the magnitude of its natural gas production, in the 1930s Exxon built its own gas pipeline transmission system, now known as the Exxon Gas System (EGS). EGS was built so Exxon could enhance the market for its own gas by selling it directly to industrial consumers and public utilities within Texas. The system, which by 1974 had grown to a length of about 1500 miles, consisted of two primary lines: one line running from a point near Corpus Christi in south Texas to a point near Tyler in northeast Texas, and a second line running east from Houston toward the Louisiana border at Port Arthur. To support the major capital commitment required for the extension of EGS, Exxon needed an assured market for its gas. Exxon secured that market in the 1950s and 1960s by entering into long-term gas sales contracts, known as the Texas Industrial Commitments contracts (TICs). During the taxable year at issue here, seventeen of these long-term contracts were in effect. At oral argument, the parties appar-

ently agreed that the bulk of the gas at issue in this case was gas sold under these TIC contracts.

Gas delivered to EGS from the tailgates of the natural gas processing plants (residue gas) or directly from the producing property via gathering line or transmission line (non-processed gas). Most of the gas that was delivered to EGS was sold to Exxon's customers, predominantly under the TIC contracts. About ten percent of the gas transported through EGS was delivered to Exxon's refinery and chemical complex at Baytown, Texas. A minor portion of the gas was used as fuel in EGS operations. At Exxon's refineries and chemical facilities, the natural gas liquids were further refined and processed into products such as gasoline, propylene, and ethylene, which ultimately were sold to customers.

B. How Exxon Determined the "Gross Income" of its Gas Properties

For the 1974 tax year, Exxon determined the value of the residue and non-processed gas produced on the properties using its "field price" for the gas.[5] The field price also represented the "constructive price" in the case of methane, which was processed and conditioned by Exxon to meet stringent pipeline specifications and delivered to EGS. Exxon based its field price on the volume-weighted average price for which producers sold gas to pipeline purchasers in the rele-

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[5] Exxon states that its "field price" was used in 1974 as the "representative market or field price" for determining its percentage depletion deduction, and was also used as a basis for calculating royalty payments, Texas gas production tax, and the sales price in arm's-length transactions with third-party working interest owners.

vant pricing areas. In those cases in which Exxon's gas plants supplied its refineries and chemical complexes with heavier liquids as chemical feedstock, the constructive transfer prices were referred to as "Exxon Posted Prices."

In determining field prices, the volume-weighted average prices were calculated for one month in each calendar quarter on the basis of data from the Form 60-1.50 Purchasers' Monthly Gas Tax reports filed with the state of Texas by pipeline purchasers. Exxon analyzed these severance tax reports, which had been filed by fifty to sixty large pipeline companies as first purchasers of gas produced in Texas and represented more than 85 percent of the gas produced in that state.[e] Because the tax reports were not available until three to four months after the relevant pricing period, the monthly average industry prices were plotted and projected forward, based on a review by an Exxon management committee, to set the field price. According to Frederick Perkins, general manager of Exxon's gas department and member of the committee establishing the field prices, Exxon's field pricing procedures were designed to ascertain what pipeline companies were paying for conditioned, processed, and compressed pipeline quality gas, not what companies were paying for raw natural gas at the wellhead. In addition, the judgment of the individual members of the pricing committee played a role in fixing the field prices. It is particularly noteworthy that Exxon did not base its 1974 field price for these properties on any analysis of *sales* of raw natural

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[e] Apparently, Exxon no longer has copies of the severance tax returns for 1974 that it initially used in the process of establishing Exxon field prices for 1974.

gas at the producing wellheads prior to conversion or transportation.[7]

Exxon established a field price for each of three geographical "pricing areas" in which were located the 504 properties, referred to as South Texas, Gulf Coast, and East Texas.[8] For 1974, Exxon established the following field prices per thousand cubic feet (mcf):[9]

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[7] Mr. Perkins further testified at his deposition that Exxon no longer has copies of the severance tax returns from 1974 that it examined, and that it no longer has copies of workpapers that would be essential to verify the accuracy of the Exxon field prices from 1974. Having learned that the State of Texas also did not have copies of these tax returns, the government commissioned an expert, Kirt Keelan, to analyze Exxon's returns. Mr. Keelan is a petroleum consultant from the firm of Forrest A. Garb & Associates, Inc. He concluded that the returns he received from Exxon did not indicate that Exxon reported prices for natural gas transfers that were similar to the Exxon field prices.

As of December 1990, Exxon apparently still had not made any analysis of sales of raw natural gas producing wellheads prior to conversion or transportation with respect to 1974 production in eastern and southern Texas.

[8] The "South Texas" area consists of Texas Railroad Commission Districts 1, 2 and 4. The "Gulf Coast" area consists of Texas Railroad Commission District 3 plus Jackson, Lavaca, Milam, Robertson, Angelina, San Augustine, and Sabine counties. "East Texas" is Texas Railroad Commission Districts 5 and 6 less the counties listed with the Gulf Coast area. (By way of explanation, for historical reasons, in Texas the tracking of the oil and gas industry in maintained by the Texas Railroad Commission.)

[9] These prices do not take into account "new" gas, gas that had been produced from a reservoir discovered by drilling after 1971 or from a field first connected to EGS after 1971. "New" gas represents less than two percent of the gas in issue in this case.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
South Texas	$.25	$.28	$.30	$.33
Gulf Coast	.29	.32	.40	.50
East Texas	.24	.27	.27	.27

On its 1974 federal income tax return, Exxon took the natural gas depletion deduction allowed in the Internal Revenue Code.[10] This depletion deduction is based on a percentage of the gross income generated by the property.[11] Exxon computed its gross income from the property attributable to the natural gas produced from each of the 504 properties by determining a separate gross value at the wellhead for each natural gas product sold or used by Exxon, and adding these values together to derive the total gross value at the wellhead of the raw gas system.[12]

As mentioned above, raw natural gas produced at the wellhead typically becomes one of three types of gas. Among these is non-processed gas. For the non-processed gas in issue, Exxon calculated the gross value at the wellhead by multiplying the applicable field price by Exxon's gross working interest gas volume and reducing the product by the amount (if

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[10] I.R.C. § 611.

[11] I.R.C. § 613.

[12] During 1974, Exxon's share of the raw gas produced from the 504 properties (net of injections, royalty, and other working interest shares) was 759,403,949 mcf. Of this amount, Exxon used its field price to determine its gross income from the property for 546,360,910 mcf. Defendant apparently disputes the use of the Exxon's field price in determining gross income from the property with respect to 500,226,473 mcf of the gas in issue.

any) of costs incurred for field compression, dehydration, and gathering of the gas. The "gross income from the property" calculated for the raw gas stream that was not processed prior to sale was this gross value at the wellhead, reduced by the royalties paid on the raw gas stream.

Processing the natural gas produces natural gas liquids and residue gas. Exxon calculated the gross value at the wellhead for the portion of the raw gas stream converted into natural gas liquids by multiplying the market value for each natural gas liquid product (the sale price or, in the absence of a gas plant sale, the fair market value at the plant) by Exxon's gross working interest share of the volume of that product credited back to the lease under the applicable processing agreement. For residue gas, the gross value at the wellhead was calculated by multiplying the applicable field price by Exxon's gross working interest share of the residue gas volume and reducing the product by the amount (if any) of costs incurred for field compression. The "gross income from the property" for the raw gas stream that was processed was the sum of the gross values at the wellhead for the liquid portion and the residue gas portion of the raw gas stream, reduced by the royalties paid with respect to that gas.

Through these various formulas, Exxon concluded that the sum of gross incomes from the property attributable to gas produced from all of the 504 properties was $272,292,009, and reported this sum on its 1974 tax return. Exxon also reported gross income from the property, net of royalty and other working interest owned shares, of $566,298,973, attributable to oil and condensate production. Accordingly, Exxon's return reported $838,590,982 in total

gross income from the 504 properties, income from which the allowable percentage depletion deduction could be taken.

C. Calculating the § 613 Depletion Deduction

Having calculated the "gross income from the property," Exxon proceeded to calculate its allowable depletion deduction. Section 611(a) of the Internal Revenue Code provides:

> In the case of mines, oil and gas wells, other natural deposits, and timber, there shall be allowed as a deduction in computing taxable income a reasonable allowance for depletion and for depreciation of improvements, according to the peculiar conditions in each case; such reasonable allowance in all cases to be made under regulations prescribed by the Secretary.

Section 613 provides that

> the allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of the gross income from the property excluding from such gross income an amount equal to the rent or royalties paid or incurred by the taxpayer in respect of the property. Such allowance shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion).
>
> . . . .
>
> (b) Percenage depletion rates.—The mines, wells, and other natural deposits, and the percentages, referred to in subsection (a) are as follows:

(1) 22 percent—

(A) oil and gas wells . . . .

Exxon multiplied its gross income from the property amounts for each of the 504 properties by the 22 percent rate to compute its deduction with respect to each property. Exxon further determined the "taxable income from the property" limitation for each of these properties by subtracting all appropriate deductions from each property's gross income and multiplying the remainder by 50 percent. To determine the percentage depletion deduction for each property under the rule of § 613, Exxon selected the greater of (a) the "22 percent" figure (subject to the "50 percent limitation") or (b) the cost depletion amount, if any. Having made these calculations, Exxon claimed depletion deductions under these provisions of $184,093,768 on its return.

Exxon paid its tax. Thereafter, the Commissioner of Internal Revenue audited Exxon and determined that on its return Exxon had overstated its total gross income with respect to the 504 properties by $50,253,856. The government also maintains that Exxon, in its computations, failed to exclude certain royalty payments, which inflated its gross income from the properties. Deficiencies and interest were assessed, which Exxon paid.[13] These deficiencies re-

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[13] A deficiency and interest were assessed against Exxon in the amount of $132,539,584.56 ($52,694,101 in tax and $79,845,483.56 in interest) on December 30, 1985, $8,155,850.92 ($2,665,367 in tax and $5,490,483.92 in interest) on December 22, 1987, $9,008,554.54 ($2,665,367 in tax and $6,343,187.54 in interest) on December 28, 1988, and $16,285,945.54 ($6,739,242 in tax and $9,546,703,54 in interest) on December

lated in part to the Commissioner's audit adjustment reducing the $184,093,768 in depletion deductions claimed by Exxon by $11,105,698. As a result, Exxon's federal income tax liability for 1974 increased by $5,330,734.

D. The Dispute: The Proper Representative Market or Field Price

It seems clear that the Commissioner arrived at this adjustment by employing a "net-back" methodology, under which he subtracted from Exxon's revenues from the sale of residue and non-processed gas under the TIC contracts both the transportation costs incurred by the company in delivering the gas to its customers and the royalties and payments made to other working interest owners. The net-back methodology supposedly was used by the Commissioner for the first time for the 1974 tax year. During the audit for 1974, the Commissioner also proposed to use the net-back methodology for the tax years from 1968 to 1973, but changed his mind after receiving information demonstrating that the net-back methodology for 1968 through 1973 would have yielded higher, not lower, depletable gross income. The depletable gross income for residue and non-processed gas as determined by the Commission's net-back method and the figures generated by Exxon's return method for the tax years 1968-1974 are as follows:

26, 1989. Exxon paid these deficiencies on December 30, 1985, December 31, 1987, December 30, 1988, and January 8, 1990, respectively.

	Total Sales Amount	Royalty and other Payments	Transportation Costs	Depletable Income Per Net-Back	Depletable Income Per Return
1968	95.3	11.7	6.4	77.2	58.8
1969	102.9	13.2	6.5	83.2	69.8
1970	116.6	14.5	7.0	95.1	77.1
1971	124.1	15.8	7.5	100.8	83.1
1972	136.2	17.5	8.1	110.6	91.3
1973	143.6	19.9	8.7	115.0	99.8
1974	162.4	32.2	11.7	118.5	168.8 [14]

The Service's audit was based on its view that for the purpose of a depletion deduction, "gross income" from the property cannot exceed actual total sales revenues, as the table above indicates was the case in 1974. This, in essence, is the basis for the government's motion for judgment on the pleadings. After the audit, the Service's refusal to refund the deficiency, and Exxon's filing suit in this court, the government also took the position that even if Exxon were allowed to base its gross income from the property on a representative market or field price, the field price Exxon used in its 1974 return is not an appropriate field price with which to calculate a depletion deduction under § 613. This position forms the basis for defendant's motion for summary judgment.

II

Before the court are two motions filed by the government—one for judgment on the pleadings and one

[14] As demonstrated in this table, the "glitch" at bottom in this matter is that in 1974 Exxon's depletable income exceeded its sales revenues, apparently the first time that this had happened. One can reasonably speculate that the sudden jump in depletable income between 1973 and 1974 is attributable to the oil embargo of 1973-74. *See Aeron Marine Shipping Co. v. United States*, 26 Cl. Ct. 946, 954-56 (1992).

for summary judgment. The rules of this court provide that if matters outside the pleadings are presented to and not excluded by the court on a motion for judgment on the pleadings, the motion shall be treated as a motion for summary judgment. The parties have submitted the evidentiary support outside the pleadings required for a summary judgment motion, but throughout this litigation the pleadings motion has had an existence of its own.[15] Because of this, and because the court's conclusions on the pleadings motion might make its interpretation of the summary judgment motion more clear, for the purposes of this order the two shall be treated as separate and distinct.

The government's motion for judgment on the pleadings is based on the uncontested fact that plaintiff's gross income for the gas generated on these properties exceeds the actual total sales revenues from this gas. As indicated above, this reasoning formed the basis for the IRS's deficiency assessment. The government argues its contention in this regard is supported by the basic depletion statute, applicable regulations, and supporting case law. Exxon, on the other hand, argues that its depletion deduction claim was calculated in strict compliance with statute, regulation, and precedent.

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[15] Soon after filing suit, Exxon moved for summary judgment. After an allowed period of discovery, the government offered its opposition and cross-moved for summary judgment. Two months later, it moved for judgment on the pleadings, focusing solely on the legal issue presented by its statutory interpretation of § 613. Later, admitting to the existence of a material fact issue that would preclude summary judgment in its favor, Exxon withdrew its motion. Thus, the government's two motions remain to be decided.

A. Standards for a Motion for Judgment on the Pleadings

Recently, this court comprehensively reiterated the standards for deciding a motion for judgment on the pleadings in *J.M. Huber Corp. v. United States*, 27 Fed. Cl. 659, 661-662 (1993). For purposes of ruling on a motion for judgment on the pleadings, the traditional standard is that a court must assume that all well-pleaded facts in the non-movant's pleading are true, that all controverted assertions of the movant's pleadings are false, *Hospital Bldg. Co. v. Trustees of Rex Hospital*, 425 U.S. 738, 740 (1976), and the court must ignore any assertions in the pleadings that amount to legal conclusions. *Olpin v. Ideal Nat'l Ins. Co.*, 419 F.2d 1250, 1255 (10th Cir. 1969). The motion therefore cannot be granted if the non-moving party has alleged facts that, if proved, would prevent the movant from prevailing. *Austad v. United States*, 386 F.2d 147, 149 (9th Cir. 1967). This court's predecessor, the Court of Claims, adopted a more rigorous standard, namely: "A motion for judgment on the pleadings should be denied unless it appears to a certainty that plaintiff is entitled to no relief under *any* state of facts which could be proved in support of his claim." *Branning v. United States*, 215 Ct. Cl. 949, 950-51 (1977) (emphasis supplied). This more rigorous standard has been approved of in this court. *See generally J.H. Huber Corp.*, 27 Fed. Cl. at 662. Therefore, the sufficiency of plaintiff's claim as stated in its complaint, reframed in its pretrial filings, or constructed in response to defendant's arguments will be judged by measuring all facts thus far identified against the legal components of a given cause of action. *Id.*

B. Construing the Code and its Regulations

The government's motion turns on the interpretation of § 613 and a part of a corresponding regulation written by the Internal Revenue Service. In questions of statutory construction, the starting point in every case is the language itself. *Johns-Manville Corp. v. United States*, 855 F.2d 1556, 1559 (Fed. Cir. 1988) (quoting *Greyhound Corp. v. Mt. Hood Stages, Inc.*, 437 U.S. 322, 330 (1978)). This is not merely a recitation of the obvious, for there are instances when the plain language of a statute does not express the intent of the legislature with the force of precision. When such an instance arises, the plain meaning of the statute will prevail absent a very clear legislative intent to the contrary. *Aaron v. SEC*, 446 U.S. 680, 697 (1980). If the meaning of a statute can be discerned within its words and does not produce an absurd result, that construction should control, and no resort should be made to extrinsic aids such as legislative history. The Federal Circuit has expressed this directly with respect to tax law, stating that " '[w]here the language is plain and admits of no more than one meaning the duty of interpretation does not arise and the rules which are to aid doubtful meanings need no discussion.' " *Henry v. United States*, 793 F.2d 289, 293 (Fed. Cir. 1986) (quoting *Caminetti v. United States*, 242 U.S. 470, 485 (1917)).

It is possible, though, for a statute to offer a plain meaning and a not-absurd result, but still not express the intent of Congress. Although statutory construction should begin and end with the language if it is clear, the legislative history may be examined for the purpose of determining whether the "plain"

meaning of the text is indeed as clear at first glance as the language would otherwise evince. Here. the court follows the Federal Circuit, which in *Madison Galleries, Ltd. v. United States* stated:

> Where the plain language of the statute would settle the question before the court, the legislative history is examined with hesitation to determine whether there is a clearly expressed legislative intention contrary to the statutory language. . . . Sometimes the literal language of some part of a statute may seemingly contradict the intent of the statute taken as a whole. . . . *Absent a clear cut contrary legislative intent, the statutory language is ordinarily regarded as conclusive.*

Madison Galleries Ltd. v. United States, 870 F.2d 627, 629-30 (Fed. Cir. 1989), *quoted in J.M. Huber Corp. v. United States*, 27 Fed. Cl. 659, 664 (1993) (emphasis supplied).

For this case, the court must also note that Treasury regulations, like the Internal Revenue Code they explain, should be examined by a similar "plain meaning" standard. If the terms of a regulation are unambiguous, they should be accorded their plain and obvious meaning. *Long v. United States*, 10 Cl. Ct. 46, 54 (1986). Treasury regulations must be sustained unless unreasonable and plainly inconsistent with the revenue statutes. *Commissioner v. South Texas Lumber Co.*, 333 U.S. 496, 501 (1948).

In its motions, the government urges that the controlling regulation, if interpreted by examining the plain language alone, produces an absurd result which does not harmonize with the statute the regulation was drafted to explain. The court agrees with the

government that the discrete legal issue to be resolved is whether the law permits percentage depletion deductions to be based on figures that exceed actual sales revenues. The government's perspective on this question is influenced heavily by its reading of the legislative history of § 613, and so to determine if the regulation as simply interpreted departs from congressional intent the legislative history of the statute must be examined.

C. The Background of the Depletion Deduction

1. Congress Provides for Depletion Deductions

Congress first allowed taxpayers to take deductions for depletion in determining the taxable income generated from natural resources in 1913, Revenue Act of 1913, Pub. L. No. 63-16, § II(G)(b), 38 Stat. 114, 172-73 (1913). Depletion is the exhaustion of natural resources, such as mines, wells, and timberlands as a result of severance production. The deduction returns to the owner or extractor of the resources his capital investment pro rata over the resources' productive life. In addition to allowing the taxpayer to regain his capital expenditures, the depletion deduction was based in the belief that it would encourage "extensive exploration and increasing discoveries of additional minerals to the benefit of the economy and strength of the Nation." *United States v. Cannelton Sewer Pipe Co.*, 364 U.S. 76, 81 (1960). The depletion deduction first specifically referred to oil and gas wells in 1916. Revenue Act of 1916, Pub. L. 64-271, § 12(a) (Second), 39 Stat. 756, 768 (1916).

The depletion deduction was modified soon thereafter in 1918, when Congress allowed oil and gas producers to take a deduction based on "discovery depletion," in which the deduction would be "based upon

the fair market value of the property at a date of the discovery" of the resource. Revenue Act of 1918, Pub. L. No. 65-254, § 234(a)(9), 40 Stat. 1057, 1078-79 (1919). The Treasury regulation implementing the discovery depletion deduction provided that the fair market value of a mineral property was to be determined by the present value at the date of discovery of the reserve's estimated future value upon production. Treas. Reg. 45, art. 206 (1921). But, to protect against abuses of this depletion allowance, in 1921 Congress provided that the "depletion allowance based on discovery value shall not exceed the net income, computed without allowance for depletion, from the property upon which the discovery is made . . . ." Revenue Act of 1921, § 234(a)(9). A Senate Report on the bill explains that the law was modified "to make certain that the depletion deduction when based upon discovery value shall not be permitted to offset or cancel profits derived by the taxpayer from a separate and distinct line of business . . . ." S. Rep. No. 275, 67th Cong., 1st Sess. 14-15. In 1924, this limitation fixed by net income was drawn tighter still as Congress moved to reduce the allowable depletion deduction to 50 percent of the taxpayer's net income from the property. Revenue Act of 1924, ch. 234, 43 Stat. 253 (1924).[16]

2. Percentage Depletion Deductions are Adopted

Discovery depletion, however, quickly produced problems of administration. A 1926 House Report remarked that

> the administration of the discovery provision of existing law in the case of oil and gas wells has

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[16] *See infra* note 19 and accompanying text.

> been very difficult because of the discovery valuation that had to be made in the case of each discovered well. In the interest of simplicity and certainty in administration the Senate amendment provides for a percentage depletion method of calculation.

H.R. Rep. No. 356, 69th Cong., 1st Sess. 31 (1926). Congress determined that instead of discovery depletion, "the best way to [determine the depletion deduction] is to provide that an arbitrary percentage on the gross value of each year's yield be chalked off for depletion. We figure it on gross income instead of net income, because the net income from oil wells varies greatly." 67 Cong. Rec. 3762 (1926). The approximate percentage to be used by producers was fixed at 27½ percent. The new percentage depletion deduction was enacted by Congress in 1926, Revenue Act of 1926, § 204(c)(2), ch. 27, 44 Stat. 9 (1926). The statute provided:

> In the case of oil and gas wells the allowance for depletion shall be 27½ per centum of the gross income from the property during the taxable year. Such allowance shall not exceed 50 percentum of the net income of the taxpayer (computed without allowance for depletion) from the property, except that in no case shall the depletion allowance be less than it would be if computed without reference to this paragraph.

The change in the Code was welcomed "as a means of simplifying the administration of the 'discovery depletion' allowance under which depletion had been based on the fair market value of the mineral property after the discovery of the valuable resource."

Hugoton Prod. Co. v. United States, 161 Ct. Cl. 274, 277, 315 F.2d 868, 869 (1963).

Although discovery depletion deductions were phased out in favor of ones based on the fixed percentages, the reason for allowing the deduction (providing for the recovery of capital expenditures) did not change. Importantly, what did change was the referent upon which the deduction would be based: the "fair market value" measure adopted in 1918 was replaced by a calculation based on "gross income from the property." When the percentage depletion section was adopted, Congress did not define gross income. The term had, however, been addressed in Treasury regulations dating to the adoption of the net income limitation on depletion deductions in 1921. Treasury Regulation 62, article 201(h), adopted in connection with the Revenue Act of 1921, provided the following idea for "gross income from the property": "If the mineral products are not sold as raw material but are manufactured or converted into a refined product, then the gross income shall be assumed to be equivalent to the market or field price of the raw material before conversion." This regulation indicates that even before percentage depletion was adopted, the deduction was to be pegged to the value of oil in its most rudimentary state instead of any refined state, preventing extractors from overrepresenting the value of their products due to product refining of some sort.

This regulation apparently did not stop some companies from reporting figures for purposes of deduction based on a value of the product in a more refined state. Having adopted the Revenue Act of 1926 (and with it percentage depletion), the Congressional Joint

Committee on Internal Revenue Taxation remarked in a report on the new legislation that "[t]he larger [gas-producing] companies have probably reported gross income from sales to the consumer rather than from the price of gas as delivered from the property." Preliminary Report—Depletion—Oil and Gas Revenue Act of 1926, 69th Cong., 1st Sess. 23 [hereinafter 1926 Report]. Accordingly, the report determined that to prevent abuses of this sort,

> [i]n the case of taxpayers who are operators, refiners, transporters, etc., the gross income from the property must be computed from the production and posted price of oil, as the gross receipts from a refined and transported product cannot be used in determining the income as relating to an individual tract or lease.

Id. at 12-13. The Joint Committee's thoughts were expressed in Treasury regulation 74, article 221(i), promulgated pursuant to the Revenue Act of 1928, which provided the following rule for computing gross income from a refined oil or gas product sold away from the wellhead:

> If the oil and gas are not sold on the property but are manufactured or converted into a refined product or are transported from the property prior to sale, then the gross income shall be assumed to be equivalent to the market or field price of the oil and gas before conversion or transportation.

Slight amendments were made to this regulation in 1933 and 1936. When the 1939 Internal Revenue Code was adopted, adjustments were made to the regulation once again, but the substance of the provision did not change.

With the statute and the new regulation in place, oil and gas producers could take percentage depletion deductions based on income generated by the property, with the income pegged to the value of the resource in its unrefined state at the wellhead. Producers of hard minerals were not allowed to take a similar deduction. The Treasury was hesitant to extend percentage depletion to mineral producers because it was even harder to determine the value of hard minerals in their unrefined state than it was to determine the value of unrefined gas. The Treasury discussed the administrative differences between oil and gas and hard minerals through the testimony of B.H. Bartholow, Special Assistant to the Secretary of the Treasury, who testified before Congress that

> while the bureau is having difficulty in administering the percentage depletion provisions in the case of oil and gas wells, the Treasury believes that the problem of administering like provisions in the case of mines would be infinitely greater. The foremost reason is that the field price of the oil or gas at the well indicates the income from the property, while in the mining industry, where there is no general field price for the ore at the mine and where the larger taxpayers do their own concentrating, smelting, refining, transporting, and marketing, all that is known is that the refined or fabricated product was sold for a certain amount. There is thus presented the insuperable difficulty of dividing up the resulting income among all those various activities—marketing, thansporting, smelting, refining, mining, etc.—and then allocating the proper portion

> to the mining operation which would be the income from the mine.

Hearings before the Joint Committee on Internal Revenue Taxation, 71st Cong., 3d Sess. 111 (1930).

Percentage depletion was extended to metal, coal, and sulphur mines in 1932. As with oil and gas properties, the deduction was to be calculated as a percentage of "gross income from the property." In Treasury Regulation 77, article 221(g), adopted in 1933, gross income was defined as

> the amount for which the taxpayer sells (a) the crude mineral product of the property or (b) the product derived therefrom, not to exceed in the case of (a) the representative market or field price . . . or in the case of (b) the representative market or field price . . . of a product of the kind and grade from which the product sold was derived, before the application of any processes. . . .

The depletion deduction statute in effect in 1974 provided, in pertinent part:

> [T]he allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of the gross income from the property excluding from such gross income an amount equal to the rent or royalties paid or incurred by the taxpayer in respect of the property. Such allowance shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion).

I.R.C. § 613(a).

3. Treasury Regulation § 1.613-3

The relevant statutory provisions and regulations for the 1974 taxable year which govern the present dispute have changed only insignificantly since the 1930s. The limitation confining the deduction to fifty percent of "net income from the property" was changed to "taxable income from the property" in 1954. The governing language of § 613 was adopted by the Public Debt and Tax Rate Extension Act of 1960, Pub. L. No. 86-564, 74 Stat. 290. Thus, for the 1974 taxable year, the determination of gross income from oil and gas producing properties was made with reference to Treasury Reg. § 1.613-3(a):

> In the case of oil and gas wells, "gross income from the property", as used in section 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is manufactured or converted into a refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil or gas before conversion or transportation.

The language of this regulation, governing the sale of oil and gas away from the well premises, did not change significantly for years. Still, there was some concern that the field price of a produced resource could be greater than the price actually received by the producer for the resource under a pre-existing contract for sale, concerns that first arose in the 1920s. Recognizing that a field price could in fact be higher than a price based on actual revenues from off-

premises sales, the Treasury promulgated a regulation, applying to hard minerals only, establishing a rebuttable presumption that such a market price is not representative. Specifically, Regulation § 1.613-4 (c)(6), put into its current form in 1972, provides:

> It shall be presumed that a price is not a representative market or field price . . . if the sum of such price plus the total of all costs of the nonmining processes (including nonmining transportation) which the taxpayer regularly applies to his ore or mineral regularly exceeds the taxpayer's actual sales price of his product. . . . In order to rebut the presumption . . . it must be established that the loss on nonmining operations is directly attributable to unusual, peculiar, and nonrecurring factors rather than to the use of a market or field price which is not representative.

As is apparent, this regulation applies to hard minerals only, and not to oil and gas production. At one point the Secretary of the Treasury proposed extending the regulation to cover oil and gas as well, but the proposal was withdrawn, leaving the language in § 1.613-3(a) unchanged. 36 Fed. Reg. 19256 (1971); 33 Fed. Reg. 10700 (1968).

The foregoing summarizes the history of the Code language and Regulation § 1.613-3(a) through 1974, the taxable year in issue. In its brief, Exxon urges that the plain meaning of the regulation is supported by an analysis of its life in the Code. The court agrees with Exxon that the regulation's plain meaning is indeed supported by its evolution. Here, the legislative history clearly indicates that the focal point of a depletion deduction was to be the price of the re-

source at the wellhead, deemed to be the representative market or field price. There is no persuasive indication that Congress intended sales prices of the gas to be determinative or that sales prices constituted a ceiling above which no deduction could be allowed.

a. Defendant's Motion

Exxon pleads and admits that the price at which it sold its gas was less than the representative market or field price, and that it used a representative market or field price as the measure of its gross income from the property in computing its depletion deduction. Reduced to its core, the government's motion for judgment on the pleadings contends that Congress intended the field price to limit gross income for calculating depletion deductions, and therefore gross income from the property cannot in any circumstance exceed the gross revenue from a producer's sales of the gas.

b. Exxon's Interpretation of the Regulation (and Applicable Precedent)

Exxon's argument in response to the government's motion for judgment on the pleadings is essentially the set of three contentions. The first is that the plain language of the regulation insists on the use of a market comparison method. Section 611 of the Code allows for a deduction representing depletion to be taken, and that the deduction is to be calculated as provided by the regulations. Regulation 1.613-3(a) establishes the now-familiar definition that the deduction shall be based on gross income, which in turn shall be assumed to be the representative market price of the resource. Court must turn to the regulations promulgated by the Treasury if the language of the statute does not operationally define key terms, and

the plain language of a regulation should control as it is assumed that a regulation means what it says. Regulations have the force and effect of law, and here the court examines a regulation that states clearly that "the gross income from the property *shall* be assumed to be equivalent to the representative market or field price . . . ." (emphasis supplied). Under the standards that have been approved in this circuit for interpreting Treasury regulations, the court is inclined to accept Exxon's interpretation.

That the plain language of the regulation produces a rational, intended tax rule is supported by what can be called Exxon's second contention: its interpretation of the regulation, as opposed to the government's, makes more sense in the context of depletion deductions. As the discussion of the legislative history of the depletion deduction indicates, those who shaped this area of the law felt that the best indication of the true "value" of a resource is what the resource is worth before it is refined. One recalls the 1926 Joint Committee report, which stated that gross income must be calculated from the production price of oil instead of from the receipts generated by the refined product. As Exxon notes, the regulation specifically provides for this method of valuation to peg the value of the oil or gas to its worth at the wellhead. The very purpose of a depletion deduction is to return to a well operator the value of his capital investment, an investment that is returned over the useful life of the resource base. The value at the wellhead, if it can be determined, should control. That the wellhead price should be examined is supported by the shift from discovery depletion to percentage depletion described above: Congress found that percentage depletion would be an easier way of calculating the depletion of

the resource because the Treasury would no longer need to determine the value of the well's resource on the date of its discovery.

Exxon's third contention is that its interpretation of the regulation has found approval in the courts. Two cases in this court's predecessor, the Court of Claims, considered the propriety of using a representative market or field price to determine the taxpayer's depletion deduction. The government correctly asserts neither *Hugoton Production Co. v. United States*, 161 Ct. Ct. 274, 315 F.2d 868 (1963) [*Hugoton I*], *Hugoton Production Co. v. United States*, 172 Ct. Cl. 444, 349 F.2d 418 (1965) [*Hugoton II*], nor *Panhandle Eastern Pipe Line Co. v. United States*, 187 Ct. Cl. 129, 408 F.2d 690 (1969) [*Panhandle*] resolved whether a taxpayer who sells gas away from the wellhead can calculate its depletion deduction using a market price if the market price were to exceed the gross revenue actually received from the buyer. These cases, however, do examine the law of depletion deductions generally and the regulation specifically and provide instruction that must be heeded even if we are not now examining the precise issues that were once before the Court of Claims.

In *Hugoton I* the taxpayer, an integrated gas producer, contended that its gross income for depletion purposes should be computed by multiplying the quantity of gas which it processed and sold in a year by the representative market or field price at the wellhead (the "market comparison" method). The government responded that since there was no representative price for the gas, the gross income should be calculated by taking the gross proceeds from the sale of plaintiff's processed gas and subtracting therefrom

all costs attributable to gathering and processing the gas (the "proportionate profits method"). (The court notes that this is the method the IRS used to compute the depletion deductions it allowed plaintiff in this case.) The court turned first to the applicable regulation, 1.613-3(a), and noted that this regulation was "of unquestioned validity, and [is] thus binding upon both parties." *Hugoton I*, 161 Ct. Cl. at 279-80, 315 F.2d at 871. The regulation had "remained substantially unchanged through a series of enactments[, and '] regulations and interpretations long continued without substantial change, applying to unamended or substantially reenacted statutes, are deemed to have received congressional approval and have the effect of law.' " *Id.* at 280 n.14, 315 F.2d at 871 n.14 (quoting *Helvering v. Winmill*, 305 U.S. 79, 83 (1938)).

Although the Court of Claims approved the use of a market comparison method for calculating gross income, it did so notwithstanding a recognition that the method had "inherent uncertainties." The government contended that there was no representative or field price for the raw gas at the wellhead, and the court found in its findings that "[b]ecause there are a variety of factors causing differences in the value of natural gas located within the same or nearby fields, because relatively small proportions of gas are sold at the wellhead, and because almost all such sales are under long-term contracts ," *id.* at 280, 315 F.2d at 871, constructing a market price is difficult. Nevertheless, the court was compelled to accept the plaintiff's approach and use the calculation method that best reflected the mandate of the governing regulation. The court stated:

> We do not say that as an original matter the proportionate profits method might not prove more

> appropriate or feasible than the market comparison approach, or that the Commissioner of Internal Revenue could not validly embody this method in its regulations. Indeed, we recognize that despite its complexities, the proportionate profits method has the advantage of being related directly to the taxpayer's own income and of allowing computation of tax liability by reference only to the taxpayer's books. Nonetheless, the CIR—not without realizing the possible alternatives and their relative advantages and disadvantages—has chose the market comparison method, and he has defended its application when productive of larger revenues. On the basis of the record compiled in this case, we are convinced that the problem of determining a representative market or field price for this taxpayer's gas is not of such unusual or inordinate difficulty as to preclude use of the method prescribed as the norm by the applicable regulations.

Hugoton I, 161 Ct. Cl. at 282-83, 315 F.2d at 872-73.

The Court of Claims remanded the case to the trial commissioner to determine the representative market price based on the average of all contracts in effect in each year under which comparable gas was sold. Plaintiff objected to the later determination on the ground that the government's figures incorrectly used interstate sales of gas—a problem (plaintiff averred) because it had only sold gas intrastate. Plaintiff's idea was to except to these findings and call on the court to decide that no comparative sales could be determined and that therefore a proportionate profits formula should be used instead of a market comparison. Noting that this was the very idea it had rejected

in *Hugoton I*, in *Hugoton II* the Court of Claims held that a market comparison had to be used. The court referred to *United States v. Cannelton Sewer Pipe Co.*, 364 U.S. 76 (1960), which held that the depletion allowance is intended to be based on the constructive income from a raw product if marketable in that form and not on the value of the finished article. Accordingly, the court in *Hugoton* concluded that permitting the plaintiff to use a proportionate profits formula would violate the spirit of *Cannelton*. Under *Cannelton*, "for purposes of depletion, integrated producers are to be treated on the same footing as those of his [sic] competitors who choose not to integrate. Having established a wellhead price, those processes increasing the value of the gas must necessarily be held to be of no consequence." *Hugoton II*, 172 Ct. Cl. at 458, 349 F.2d at 426-27. Further, *Hugoton II* reiterated that if a representative price can be determined for the oil or gas, then that price must be used in a market comparison. Unlike hard minerals, for which a taxpayer can choose the alternative proportionate profits valuation if no field price can be determined, "[n]o such choice has been prescribed by the Commissioner in the oil and gas field. As can be seen clearly from the Regulation quoted earlier in the opinion, [the Commissioner] has chosen to embody in it only one concept—'representative market or field price.'" *Id.* at 459, 349 F.2d at 427.

As noted in the *Hugoton* opinions and in *Panhandle*, fixing a representative price for a market comparison valuation can present difficulties. Before addressing the specific reasons why the government says the regulation cannot be used by plaintiff in this case, the court reiterates that it is bound to follow the letter of the regulation unless the result is patently absurd.

The court notes that, importantly, the regulation (along with its substantially similar predecessors) could have been revised on a number of occasions since the 1920s to effect a result that would perhaps more perfectly represent Congressional intent. This, however, has not been done, and the court notes that in the nine years that elapsed between *Hugoton II* and the taxable year at issue here the Commissioner did not feel compelled to change the regulation in any way.[17]

c. The Government's Counterargument

As noted earlier, the assertion driving the government's argument on its motion for judgment on the pleadings is that the Code does not allow a depletion deduction to be based on a field price if that field price exceeds the actual price obtained by sale. The government contends that the very reason why Congress enacted depletion deduction was to prevent the deduction from being calculated from anything but the net income from the gas producing property. This was manifested by the "net income" limitation, originally providing that a deduction could not exceed 100% of taxable income from the property. This particular limitation, however, expressed in the second sentence of § 613, stands apart from the first sentence of the

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[17] No doubt the Commissioner of Internal Revenue is well aware of litigation in this area. If for some reason he finds that the market comparison method is not generally workable then he would be within the ambit of his statutory powers to amend the applicable Regulation to provide some alternative method. Until that time we feel that it is not within our judicial powers to legislate in his place.

Hugoton II, 172 Ct. Cl. at 463, 349 F.2d at 430.

section which allows for the deduction to be based on "gross income from the property." [18]

The government further contends that Congress sought to prevent deductions that contained in their calculations post-extraction additives such as refinements away from the wellhead, transportation, and the like, a concept embodied (says defendant) in the representative market price. In its words, "[t]he representative market or field price is the tool used to cut back actual revenues received by taxpayers from the sale of manufactured or transported oil and gas produced in order to calculate percentage depletion deductions with respect to applicable properties." The court cannot agree that such a tool exists. The court agrees with Exxon that the government's construction of the statute allows the government to ignore the depletion calculation rules when post-production factors away from the wellhead decrease the value of the gas. In Exon's words, "the Secretary easily could have prescribed use of the 'representative market or field price' only as a *ceiling* on gross income from the property, but instead he adopted a regulatory definition that operates as a two-way street." (emphasis in original).[19]

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[18] Section 613 provides in pertinent part:

> [T]he allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of the gross income from the property excluding from such gross income an amount equal to the rent or royalties paid or incurred by the taxpayer in respect of the property. Such allowance shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion).

[19] The court is quite mindful of the general appeal of the government's fundamental argument in this case, *viz.*, it is

Finally, the government draws the court's attention to a table it has drawn up to illustrate that if gross income based on a very high representative mar-

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"absurd" to allow a taxpayer to claim a deduction based on income that isn't *actual income*, that is, income not pocketed from sales of the product. Allowing deductions based on "representative" prices may not be the clearest example of common sense for the reasonable person. Tax provisions, however, are not accidental, and the court finds that § 1.613-3, intended to implement a tax policy that encourages drilling and most accurately reflects the true value of the natural resource, cannot be massaged to avoid larger than anticipated deductions. Consider in this regard *Cohen v. United States*, No. 92-5013, slip op. at 10 (Fed. Cir. June 4, 1993): "Taxation, perhaps more so than all other relationships between government and the governed, operates within a belief on both sides that the rules should be clear and uniformly applied . . . . It is rare that tax law bears any recognizable relationship to common sense, but this one does." Unlike the court in *Cohen*, the present case does not afford the luxury of presenting a tax law that clearly comports with common sense. But, as the court has tried to show, the law, which has remained largely unchanged for years, has not suddenly become so ridiculous that it must be rejected out of hand.

Continuing on this thought, the government argues that "gross income from the property," as set out in § 613, should be interpreted in a manner not inconsistent with the term "gross income" as defined in § 61 of the I.R.C., the section that generally defines what "income" is. In other words, the government urges that gross income must have the same meaning in both sections to avoid what it sees as an unintended result. At oral argument, the government supported this argument with a reference to *Commissioner v. Keystone Consolidated Industries, Inc.*, 61 U.S.L.W. 4481, 4483 (U.S. May 24 ,1993), which stated: "It is a 'normal rule of statutory construction,' that 'identical words used in different parts of the same act are intended to have the same meaning.' *Atlantic Cleaners & Dyers, Inc. v. United States*, 286 U.S. 427, 433 (1932)." As applied to this case, the court notes

ket or field price happened to greatly exceed actual taxable income based on sales revenues, the percentage depletion deduction as calculated and allowed could far exceed the taxpayer's actual income. The court understands that such a circumstance might fly in the face of the limitations on deductions enacted as early as 1916, but if the deduction was intended to represent a return of the captial expenditure, to be based on the value of the resource (which the legislative

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that the general income definition and the depletion deduction rules, though both revenue laws incorporated into Title 26, are not parts of the same *act*; they were adopted at different times by different statutes. The Supreme Court has recognized the impact that context has on definition in, among other cases, *Atlantic Cleaners*. As the Court put it:

> Most words have different shades of meaning and consequently may be variously construed, not only when they occur in different statutes, but when used more than once in the same statute or even in the same section. Undoubtedly, there is a natural presumption that identical words in different parts of the same act are intended to have the same meaning. But the presumption is not rigid and readily yields whenever there is such a variation in the connection in which the words are used as reasonably to warrant the conclusion that they were employed in different parts of the act with different intent. Where the subject matter to which the words refer is not the same in the several places where they are used, or the conditions are different, or the scope of the legislative power exercised in one case is broader than that in another, the meaning well may vary to meet the purposes of the law, to be arrived at by a consideration of the language in which those purposes are expressed, and of the circumstances under which the language was employed.

Atlantic Cleaners & Dyers, Inc. v. United States, 286 U.S. 427, 433 (1932) (citation omitted).

history of the depletion deduction shows was the intention of Congress), the result is not so illogical. Apparently, the Commissioner agrees: the regulation is much the same as it was sixty years ago, and the court does not feel compelled to rewrite it at this time.[20]

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[20] In its motion the government urges that adopting Exxon's interpretation of the applicable regulations would allow integrated producers to use the depletion allowance to offset unrelated income, rendering meaningless the provision holding the deduction to 50% of taxable income. Regulation § 1.613-5(a), drafted by the Treasury to implement the taxable income limitation, provides:

> The term "taxable income from the property (computed without allowance for depletion)," as used in section 613 and this part, means "gross income from the property" as defined in section 613(c) and §§ 1.613-3 and 1.613-4, less all allowable deductions (excluding any deduction for depletion) which are attributable to mining processes, including mining transportation, with respect to which depletion is claimed.

This regulation clearly states that for the purpose of calculating the taxable income limitation, the gross income from the property shall be that figure provided by § 1.613-3, which is the representative market or field price (if such a market figure can be determined). Of course, Exxon responds by urging the court to apply the regulation literally and to reach a result that comports with the reading of § 1.613-3(a) it would prefer. Exxon states the application of § 1.613-5 played no part on the determination of the deficiency and was raised by the government for the first time in this litigation. As a result, Exxon questions whether the court even has jurisdiction to determine the effect of the taxable income limitation in this case. *See Ottawa Silica Co. v. United States*, 699 F.2d 1124, 1137-39 (Fed. Cir. 1983). The court need not enter this thicket for it has not been shown that the 50% limitation would be violated if the court were to accept, *arguendo*, Exxon's position as advanced herein. Exxon maintains that

In concluding, the court must reach back to the standards described earlier in this order. The plain language of the statute provides that the deduction shall be based on the gross income from the property, and the regulation says that gross income shall be assumed to be the representative market or field price before conversion or transportation. Since the plain language of this statute would clearly settle the issue on this motion, the legislative history must be examined to determine whether this language produces an absurd result. The court cannot say that an absurd result is reached. Further, the possibility that the representative price might on occasion exceed the income realized from the property was recognized by Treasury officials. Yet, the regulation at issue remained unchanged with respect to oil and gas and was modified with respect to hard minerals.[21] In the case at bar, the gross income from the properties for 1968-1973 was greater than the market value of the gas. In 1974, though, the gross income from the properties was less than the representative market value of the gas. The bearing of the seventeen long-term contracts Exxon had with various third parties, together with the effect of the OPEC oil embargo in the 1970s, *see Aeron Marine Shipping Co.*, *supra* note 14, may well have contributed to this result. On balance, the conclusion that the regulation's plain meaning should pre-

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no such violation of the 50% limitation would occur; defendant cannot say whether any such violation would in fact occur.

[21] *See Helvering v. Mountain Producers Corp.*, 303 U.S. 376, 382 (1938) ("The gross income [from a property] from time to time may be more or less than market value [of the oil and gas] according to the bearing of particular contracts.")

vail does not produce such an absurd result that it should be ignored or discarded. Although the government has identified sections of the legislative history of this provision that suggest that the depletion deduction can never exceed actual revenues for the property, there is no clear cut legislative intent that this was to be the statutory rule.[22]

For the foregoing reasons, the government's motion for judgment on the pleadings is denied.[23] The next question is whether Exxon's depletion deduction computation was based on an appropriate representative market or field price.

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[22] *Cf. Mobil Exploration and Producing North America, Inc. v. United States*, 27 Fed. Cl. 463, 468 n.6 (1993):

> Inevitably, the parties and the court must construe the meaning of the words in question and attempt thereby to arrive at what Congress meant. The legislative body is presumed to mean what it says, and only if literal meaning makes too great a departure from reason should we resort to our own speculations from evidence of concealed intent reflected in secondary materials.

[23] The government has presented other related arguments in support of its motion for judgment on the pleadings, but none changes the court's conclusions. For example, the government points to an Internal Revenue Service Revenue Ruling that concludes that the representative market or field price should be disregarded if that price happens to exceed the price for which the gas is actually sold. *See* Rev. Rul. 90-62, 1990-2 C.B. 158. This ruling, however, does not analyze 1.613-3(a) and makes no reference to the Court of Claims' analysis in *Hugoton* or *Panhandle*. The court finds the ruling unpersuasive. In any event, while they may be helpful in interpreting a statute, revenue rulings do not have the effect of a regulation or a Treasury Decision and are not binding on the court. *Xerox Corp. v. United States*, 228 Ct. Cl. 406, 426 n.6, 656 F.2d 659, 671 n.20 (1981).

III

Before the government filed its motion for summary judgment presently under consideration, Exxon itself moved for summary judgment. The government filed its response to the motion a year later, after its motion to suspend a decision on the motion was granted so that there could be some more discovery. Along with its response to plaintiff's motion, the government filed its cross-motion for summary judgment. Further factual developments relevant to the summary judgment motion (but not directly relevant to the motion for judgment on the pleadings) must be related. As indicated earlier, Exxon thereafter withdrew its motion for summary judgment, asserting that the issue of representative market or field price involved disputed issues of fact which precluded summary judgment for either party. The government, however, forged ahead in seeking summary dismissal of plaintiff's claim.

A. The Government's Challenge to Exxon's Field Prices

Along with its motion for summary judgment, Exxon filed its proposed findings of fact, including the assertion that "[t]he price at which Exxon sold the natural gas to purchasers away from the producing properties was less than the 'representative market or field price' for the gas, as that term is defined by Treas. Reg. § 1.613-3." In its statement of genuine issues filed with the court, the government argues, *inter alia*, that:

1. Exxon has never determined the "representative market or field price" for the gas as that term is defined in Regulation § 1.613-3(a). This assertion

is based on deposition testimony given by Fred Perkins, who stated that the field price generated by Exxon represents not the fair market value of the resource that comes out of the wellhead, but instead represents value of the gas at the tailgate of a processing plant. It is generally conceded that processes away from the wellhead, such as dehydration and compressing, add value to the gas. The government asserts that if Exxon did not calculate the value of raw natural gas at the wellhead before conversion and transportation, Exxon cannot survive a summary judgment motion because it cannot satisfy the requirements of the regulation.

2. Exxon used revenue figures instead of raw material figures. Purportedly, Exxon made its tax calculations from the property-by-property revenue data assembled by its natural gas department accounting group. The form this group used attributes to each property its net revenue share from each sale or other disposition of product made from the raw natural gas produced from the property. For actual sales of the numerous finished products, the revenue share was developed from applicable actual sales prices; but for gas delivered to the EGS pipeline and for other instances in which product was transferred inside the company, the revenue share was developed from constructive transfer prices, i.e., Exxon field prices for methane deliveries to EGS and Exxon posted prices for the liquids.

In response to the government's challenges, Exxon retained David B. Marks (Marks), president of the oil and gas consulting firm EnerPro, Inc., to conduct a study of 1974 wellhead sales of natural gas in Texas. Marks compiled a list, for the relevant producing areas, of 1974 sales of unprocessed natural

gas that occurred before the gas was transported from the leased premises that he could locate. Among the records he examined were information concerning such sales on file with the State of Texas General Land Office and the Texas Railroad Commission, Exxon's monthly gas tax reports filed with Texas, and Exxon's natural gas sales contract files. In an affidavit filed with Exxon's reply brief, Marks concluded that the gas sold in the 1974 transactions "is representative of the gas produced in Railroad Commission Districts 2 through 6 and sold at the wellhead during 1974 in terms of location, availability, quality, and type of sales contract." The volume-weighted average representative market or field price for each District was as follows:

Railroad Commission District	Volume-Weighted Average Price (Cents/mcf)
2	32.720
3	43.154
4	44.161
5	21.183
6	32.366

Better still for Exxon, Marks concluded that because Exxon's gas was of generally better quality, availability, and location than the gas sold in wellhead sales, it would have had a slightly higher market value per mcf at the wellhead than the gas reflected in his compilation. Further, Marks found that the weighted average prices computed in his study "are representative of, and perhaps slightly lower than, the prices Exxon would have received for its gas in the applicable Railroad Commission District if it had sold that gas at the wellhead during 1974 under the well-

head gas sales contracts then in effect in that district." [24]

In its reply brief in support of its motion for summary judgment, the government argues forcefully that Marks's newer interpretation of the relevant data still does not satisfy the requirements of Regulation 1.613-3. The government deposed Marks soon after his affidavit had been taken and, using this deposition testimony, explains that Marks may have examined the tax reports and public records described in his affidavit, but in fact examined only one actual Exxon contract. The contract, referred to by the government as the Duncan Slough contract, was a twenty-year gas purchase agreement dating from 1968 between Humble Oil (Exxon's predecessor in interest), the producer, and Lo-Vaca Gathering Co., the gatherer and purchaser, calling for delivery from Exxon to Lo-Vaca of pipeline quality gas after separation and dehydration by the producer and transfer of ownership from the producer to the purchaser of the methane contained in the gas after helium and liquefiable hydrocarbons were removed from the gas processing at a Dow Chemical Company gas process-

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[24] Because the prices computed by Marks were higher than the prices on which Exxon based its refund claim, Exxon asserts, through the affidavit of Freddie W. Watson, an Exxon Gas Accounting Advisor, that had Exxon valued its wellhead volume of gas at the weighted average prices compiled by Marks, its depletable gross income from the property for gas transported prior to sale would have been $53.6 million more than the amount on which Exxon's refund claim is based. The "new" 1974 gross income would have been $325,849,211 (instead of $272,292,009); the allowable deduction would be $195,962,501 (up from the $184,093,768 claimed on the tax return).

ing plant. Judging from the submissions before it, at this stage the court would be inclined to agree with the government that this contract was not for the sale of raw natural gas in the vicinity of the wellhead.

The government argues that because Marks looked at no other contracts, the only evidence Exxon submits to prove that representative market or field price for gas-producing properties in issue exceeds actual net revenues from off-premises sales is Marks' analysis, created from a search of state records based on the unsubstantiated assumption that his procedure would identify sales of unprocessed natural gas prior to transportation from the leased premises from which the gas was produced. The procedure, it is said, does not permit anyone to identify arms-length transfers at ascertainable locations on known dates for specified valuable consideration of unprocessed natural gas prior to transportation from the leased premises from which the gas was produced. The government concludes that its indictment of Marks's analysis, combined with the law in *Hugoton* and *Panhandle* that a field price must be calculated on the basis of weighted average sales prices for the applicable market area for comparable raw natural gas, compel the entry of summary judgment in its favor. As a lodestone for determining whether such a judgment can indeed be compelled at this stage of the litigation, the governing law on summary judgment motions must be examined.

B. Plaintiff's Burdens in Overcoming Summary Judgment

The United States Supreme Court explained in *Celotex Corp. v. Catrett*, 477 U.S. 317, 322-23 (1986), that

> the plain language of Rule 56(c) mandates the entry of summary judgment, after adequate time for discovery and motion, against a party who fails to make a showing sufficient to establish the existence of an element essential to that party's case, and on which that party will bear the burden of proof at trial. In such a situation, there can be "no genuine issue as to any material fact," since a complete failure of proof concerning an essential element of the nonmoving party's case necessarily renders all other facts immaterial.

The moving party's burden to show an absence of a genuine triable factual issue may be discharged by showing that there is an absence of evidence to support the nonmoving party's case. *Id.* at 325.

This standard does not itself described when the necessary supporting evidence is "absent". According to the Court in *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 250 (1986), the court must make the threshold inquiry of whether there are any genuine factual issues that properly can be resolved only by a finder of fact because they may reasonably be resolved in favor of either party. "[T]his standard mirrors the standard for a directed verdict under Federal Rule of Civil Procedure 50(a), which is that the trial judge must direct a verdict if, under the governing law, there can be but one reasonable conclusion as to the

verdict." In *Adickes v. S.H. Kress & Co.*, 398 U.S. 144 (1970), the Court used this standard and held that the trial court's entry of summary judgment was inappropriate because the moving party's submissions "had not foreclosed the possibility of the existence of certain facts from which "it would be open to a jury" to conclude that an essential element of plaintiff's case could be proven. *Anderson*, 477 U.S. at 249 (citing *Adickes*, 398 U.S. at 158-59).

Bearing these procedural standards in mind, the court's function at the summary judgment stage is not for itself to weigh the evidence and determine the truth of the matter but to determine whether there is a genuine issue for trial. *Id.* If the possibility exists that a reasonable jury considering the evidence could return a verdict for the non-movant, summary judgment should be denied. "The evidence of the non-movant is to be believed, and all justifiable inferences are to be drawn in his favor[, and the Supreme Court does not suggest] that the trial court may not deny summary judgment in a case where there is reason to believe that the better course would be to proceed to a full trial." *Id.* at 255.

C. Whether Exxon's Data Are Sufficient

If the court were to accept the government's argument that the Marks price analysis is the only evidence Exxon has presented that demonstrates the existence of an available field price, and that his methodology in deriving this price is fundamentally flawed, then Exxon could be faulted for failing to present an esential element of its case which it would have the burden of demonstrating at trial, and penalized by an entry of summary judgment against it.

Although the government has developed a substantial indictment of what Marks says represents the 1974 field prices, if the court were at this point to dismiss entirely the worth of his affidavit and data it would be engaging in a determination of witness credibility and weighing of the evidence that it can only do at trial. The resolution of this tax refund suit depends substantially on the court's comprehensive appreciation of how Exxon generated the field prices it claims, and whether these purportedly representative prices have been developed in a manner that comports with this court's precedents guiding this matter. In a statement filed with the court, the parties agreed that they had reached an impasse on at least one (but particularly important) relevant fact: whether there were wellhead sales from 1974 that can be used in calculating a representative market or field price for the gas at issue in this case. Referring to Marks's work, Exxon answers yes; the government says no. A factual dispute of such complexity and material importance is best resolved after a trial, where the factual nuances can best be explored.

IV

Accordingly, the court denies the government's motion for summary judgment. The parties have reached the end of filing dispositive motions in this suit. Unless settlement negotiations undertaken in good faith between the parties prove fruitless (and oral argument suggests that they would be), the court expects to proceed to trial. A few remarks should be made at this point, and the court hopes they will be useful in spite of the rather simple propositions the remarks express.

Initially, the court emphasizes that with respect to the summary judgment motion, all that it has decided in this order is that Exxon has presented sufficient evidence to survive the motion and put on its case. That is to say, it has presented more than a mere scintilla of evidence in its favor, *see Anderson*, 477 U.S. at 253, and the evidentiary issue it presents is not the product of mere speculation or bald assertion, *SMS Data Prods. Group, Inc. v. United States*, 19 Cl. Ct. 612, 617 (1990). Exxon, however, has not been excused from satisfying the heavy burden of proof demanded of a plaintiff in a tax refund suit.

"It is well settled in a tax refund suit there is a *strong* rebuttable presumption of the correctness of the determination of the Commissioner." *Mulholland v. United States*, No. 645-85T, slip op. at 17 (Fed. Cl. May 3, 1993) (emphasis in original) (citing *Welch v. Helvering*, 290 U.S. 111, 115 (1933); *Snap-On Tools, Inc. v. United States*, 26 Cl. Ct. 1045, 1055 (1992)). Generally, the plaintiff has the burden of rebutting this presumption. *United States v. Janis*, 428 U.S. 433, 440-41 (1976). "A tax refund suit is not a quasi appellate review of an administrative determination. In order to prevail, the taxpayer, in addition to showing the IRS action was arbitrary, capricious, or unreasonable, must prove the correct amount of the tax and resulting overpayment." *The Hearst Corp. v. United States*, No. 704-89T, slip op. at 46 (Fed. Cl. May 4, 1993). At oral argument, the government suggested that in further proceedings it would also take issue with the methodology used by the IRS to determine the depletion deduction allowed to Exxon. If so, then both parties would be attacking the presumptive correctness of the IRS determination.

The burden of not only proving the determination of a deficiency was incorrect but also proving the correct refund amount to which the taxpayer is entitled is still more difficult to meet when the disagreement with the Commissioner relates to a deduction. Deductions are a matter of legislative grace, not of right. *New Colonial Ice Co. v. Helvering*, 292 U.S. 435, 440 (1934); *The Hearst Corp.*, slip op. at 46. Exemptions and exclusions from taxable income should be construed narrowly, and a taxpayer must bring itself within the clear scope of an exemption, an exclusion, or a deduction. *Commissioner v. Jacobson*, 336 U.S. 28, 49 (1949).[25]

Finally, the court must note that even if the plaintiff in this case were to demonstrate to this court that a representative market or field price of gas sales in the vicinity of the wellhead can be reasonably established from the data it presents, that in itself does not mean that that figure will be accepted for the purposes of allowing a higher depletion deduction. As the Court of Claims did in *Panhandle*, the entire factual and contractual scenario must be visited by the court to determine if the field price proposed is a reasonable one. Such a field price could be rejected as "highly indigestible." *See Panhandle*, 187 Ct. Cl. at 171, 408 F.2d at 717. The field price must be set in a manner that best follows the statute and the regulation, but where the regulation produces a "highly indigestible" result, the court can work to find a better

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[25] Furthermore, the court notes that in lawsuits that have the potential of imposing a large financial burden on the United States, the statute in issue will be very cautiously scrutinized.—*See Alliance of Descendants of Texas Land Grants v. United States*, 27 Fed. Cl. 837, 841 n.3 (1993).

figure.[26] Though it shouldn't have to, the court expresses anew that if anyone knows best what would be a representative wellhead sales figure for these 1974 sales, it is the plaintiff and the defendant. The Commissioner initially allowed Exxon more than ninety percent of the depletion deduction it claimed from these 504 properties on its original return. This determination is deemed to be presumptively correct. The fact that both parties are going to try to rebut that presumption, in a situation where reasonable minds might differ on what constitutes a representative price might justify deference on the particular facts to the IRS's determination as one of several possible reasonable determinations.[27]

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[26] With respect to the statements and conclusions of the court in the second *Hugoton* decision referred to above, we read the language in question to mean that the applicable regulation requires the use of a "representative market or field price," *if* an acceptable price of such nature can be established. Neither the court's decision in that case nor the regulation requires the impossible, i.e., the use of a price that cannot be determined *representative*, or as precluding us from applying some other formula that produces a fair result. To hold otherwise would mean that in the instant proceeding the Government has successfully presented to plaintiff a "heads I win, tails you lose" proposition.

Panhandle, 187 Ct. Cl. at 174, 408 F.2d at 717-18 (emphasis in original) (footnote omitted).

[27] Presumably, the government would attack the IRS methodology as being inappropriate "netbacking," a technique frowned on by some courts but available to a court if no representative market price can be determined. *See Panhandle*, 187 Ct. Cl. at 170-175, 408 F.2d at 715-18.

V

For the foregoing reasons, defendant's motion for judgment on the pleadings is denied and its motion for summary judgment is also denied. The parties are directed to advise the court within thirty days of the date of this order relative to further proceedings in this case.

/s/ Thomas J. Lydon
THOMAS J. LYDON
Senior Judge

APPENDIX C

IN THE UNITED STATES COURT OF FEDERAL CLAIMS

No. 660-89T

(Filed: April 11, 1995)

EXXON CORPORATION, PLAINTIFF

v.

THE UNITED STATES, DEFENDANT

Tax refund; I.R.C. § 611 (1954) and Treas. Reg. § 1.613-3(a); percentage depletion deduction; statutory and regulatory interpreation and construction; representative market or field price (RMFP); reasonableness test.

OPINION

LYDON, Senior Judge:

The plaintiffs in this action are Exxon and other subsidiary corporations who, for convenience, will be referred to collectively as Exxon. Exxon alleges it is entitled to a refund of federal income taxes paid for the tax year ending December 31, 1974. Exxon's complaint alleges it is entitled to recover the sum of $17,164,405.46, together with interest thereon as pro-

vided by law, which sum represents an alleged overpayment by Exxon of federal income taxes in the amount of $5,330,734 and assessed interest in the amount of $11,833,671.46. This claim relates to the single issue of whether Exxon properly computed its "gross income from the property" for purposes of calculating its percentage depletion deduction for 1974 under section 613(a) of the Internal Revenue Code of 1954 (Code) with respect to natural gas produced by Exxon from 482 properties located along the Texas Gulf Coast and East Texas regions and sold under long-term contracts to industrial users in the Texas intrastate market or used by Exxon for its own operations.[1] By Order issued June 29, 1993, the court denied defendant's motion for judgment on the pleadings and for summary judgment. Trial was held from July 27 through August 10, 1994. Exxon now seeks a refund based on a "representative market or field price" (RMFP) of $.41 per Mcf.[2]

I

Exxon is in the business of exploring for and producing crude oil and natural gas in addition to the refining, transporting, buying, and selling of petro-

[1] The parties have stipulated that during 1974, Exxon produced raw natural gas from each of the properties at issue, that Exxon owned an economic interest, within the meaning of Treas. Reg. § 1.611-1(b), in each of these properties, and that each of these properties is a "property" within the meaning of Code § 614 and Treas. Reg. § 1.611-1(d)(1). The parties have further stipulated to various items necessary to determine the appropriate depletion deduction for each property.

[2] An Mcf is 1,000 cubic feet and is a standard of measure for natural gas.

leum and petroleum products. During 1974, Exxon produced approximately 861 billion cubic feet (Bcf) of raw natural gas, net of injections and other working interest shares, from the 482 properties in issue. Most of the gas produced from these properties was processed at gas plants to remove the liquefiable hydrocarbons and then transported through Exxon's own pipeline system, the Exxon Gas System (EGS), prior to sale. Exxon also sold some of the gas at its gas plant tailgates and used the remainder in its own operations, including as fuel for its Baytown, Texas refinery and chemical complex.

Exxon can be classified as a fully integrated producer of natural gas. An integrated producer is one that engages in more than one phase of the oil or gas business. A fully integrated producer is engaged in all phases of the business from exploration of the retail sale of end products. These phases include exploration and production, transportation, manufacturing or refining, and retailing or marketing. In the most limited sense an integrated producer of natural gas is one that has the ability to process or transport its gas prior to sale. Non-integrated producers do not own facilities to transport or process their gas and must sell their gas, "raw" or unprocessed in the producing area, whereas the integrated producer can elect either to sell its raw gas in the vicinity of the well or to transport or process its gas prior to sale.

The relevant statutory provisions and regulations for the 1974 tax year wihch govern the present dispute have changed only insignificantly since the 1930s. Section 611(a) of the Code provides:

> In the case of mines, oil and gas wells, other natural deposits, and timber, there shall be al-

> lowed as a deduction in computing taxable income a reasonable allowance for depletion and for depreciation of improvements, according to the peculiar conditions in each case; such reasonable allowance in all cases to be made under regulations prescribed by the Secretary or his delegate.

Section 613 provides that:

> the allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of the gross income from the property excluding from such gross income an amount equal to the rent or royalties paid or incurred by the taxpayer in respect of the property. Such allowance shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion).
>
> . . .
>
> (b) Percentage depletion rate.—The mines, wells, and other natural deposits, and the percentages, referred to in subsection (a) are as follows:
>
> (1) 22 percent—
>
> (A) oil and gas wells . . .

For the 1974 taxable year, the determination of gross income from oil and gas producing properties was made with reference to Treasury Regulation section 1.613-3(a) which provides in pertinent part:

> In the case of oil and gas wells, "gross income from the property," as used in section 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of

> the well. If the oil or gas is not sold on the premises but is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price [RMFP] of the oil or gas before conversion or transportation.

It is the second sentence, quoted above, that serves as the catalyst for this litigation.

A. The Background of the Depletion Deduction

1. Congress Provides for Discovery Depletion Deductions

Congress first allowed taxpayers to take deductions for depletion in determining the taxable income generated from natural resources in 1913. Revenue Act of 1913, Pub. L. No. 63-16, § II(G)(b), 38 Stat. 114, 172-73 (1913). Depletion is the exhaustion of natural resources, such as mines, wells, and timberlands as a result of severance production. The deduction returns to the owner or extractor of the resources his capital investment pro rata over the resources' productive life. In addition to allowing the taxpayer to regain its capital expenditures, the depletion deduction was based on the belief that it would encourage "extensive exploration and increasing discoveries of additional minerals to the benefit of the economy and strength of the Nation." *United States v. Cannelton Sewer Pipe Co.*, 364 U.S. 76, 81 (1960). The depletion deduction first specifically referred to oil and gas wells in 1916. Revenue Act of 1916, Pub. L. 64-271, § 12(a) (Second), 39 Stat. 756, 768 (1916).

The depletion deduction was modified in 1918, when Congress allowed oil and gas producers to take a deduction based on "discovery depletion," in which the

deduction would be "based upon the fair market value of the property at the date of the discovery" of the resource. Revenue Act of 1918, Pub. L. No. 65-254, § 234(a)(9), 40 Stat. 1057, 1078-79 (1919). The Treasury regulation implementing the discovery depletion deduction provided that the fair market value of a mineral property was to be determined by the present value at the date of the discovery of the reserve's estimated future value upon production. Treas. Reg. 45, Art. 206 (1921). But, to protect against abuses of this depletion allowance, in 1921 Congress provided that the "depletion allowance based on discovery shall not exceed the net income, computed without allowance for depletion, from the property upon which the discovery is made . . . ." Revenue Act of 1921, § 234(a)(9), 42 Stat. 256. A Senate Report on the bill explains that the law was modified to "make it certain that the depletion deduction when based upon discovery value shall not be permitted to offset or cancel profits derived by the taxpayer from a separate and distinct line of business . . . ." S. Rep. No. 275, 67th Cong., 1st Sess. 14-15 (1921). In 1924, this limitation fixed by net income was drawn tighter still as Congress moved to reduce the allowable depletion deduction to fifty percent of the taxpayer's net income from the property. Revenue Act of 1924, ch. 234, § 204(c), 43 Stat. 253.

2. Percentage Depletion Deductions are Adopted

Discovery depletion, however, quickly produced problems of administration. A 1926 House report remarked that:

> the administration of the discovery provision of existing law in the case of oil and gas wells has

> been vary difficult because of the discovery valuation that has to be made in the case of each discovered well. In the interest of simplicity and certainty in administration the Senate amendment provides for a percentage depletion method of calculation.

H.R. Rep. No. 356, 69th Cong., 1st Sess. 31 (1926). Congress determined that instead of discovery depletion, "the best way to [determine the depletion deduction] is to provide that an arbitrary percentage on the gross value of each year's yield be chalked off for depletion. We figure it on gross income instead of net income, because the net income from oil wells varies greaty." 67 Cong. Rec. 3762 (1926). The approximate percentage to be used by producers was fixed at twenty-seven and one-half percent. The new percentage depletion deduction was enacted by Congress in 1926. Revenue Act of 1926, ch. 27, § 204(c)(2), 44 Stat. 9 (1927). The statute provided:

> In the case of oil and gas wells the allowance for depletion shall be 27½ per centum of the gross income from the property during the taxable year. Such allowance shall not exceed 50 per centum of the net income of the taxpayer (computed without allowance for depletion) from the property, except that in no case shall the depletion allowance be less than it would be if computed without reference to this paragraph.

The change in the Code was welcomed "as a means of simplifying the administration of the 'discovery depletion' allowance under which depletion had been based on the fair market value of the mineral property after the discovery of the valuable resource."

Hugoton Prod. Co. v. United States, 161 Ct.Cl. 274, 277, 315 F.2d 868, 869 (1963) (*Hugoton I*).

Although discovery depletion deductions were phased out in favor of those based on the fixed percentages, the reason for allowing the duction (providing for the recovery of capital expenditures) did not change. Importantly, what did change was the reference upon which the deduction would be based: the "fair market value" measure adopted in 1918 was replaced by a calculation based on "gross income from the property." When the percentage depletion section was adopted, Congress did not define gross income. The term had, however, been addressed in Treasury regulations dating to the adoption of the net income limitation on depletion deductions in 1921. Treasury Regulation 62, Art. 201(h), adopted in connection with the Revenue Act of 1921, provided the following illustration of "gross income from the property."

> If the mineral products are not sold as raw materials but are manufactured or converted into a refined product, then the gross income shall be assumed to be equivalent to the market or field price of the raw material before conversion.

Treas. Reg. 62 (1922 ed.), Art. 201(h). This regution indicates that even before percentage depletion was adopted, the deduction was to be pegged to the value of oil in its most rudimentary state instead of any refined state, preventing extractors from overrepresenting the value of their products due to product refining of some sort.

This regulation apparently did not stop companies from reporting figures for purposes of deduction based

on a value of the product in a more refined state. Having adopted the Revenue Act of 1926 (and, with it, percentage depletion), the Congressional Joint Committee on Internal Revenue Taxation remarked that "[t]he larger [gas-producing] companies have probably reported gross income from sales to the consumer rather than from the price of gas as delivered from the property." Preliminary Report—Depletion—Oil and Gas Revenue Act of 1926, 69th Cong., 1st Sess. 23 (1927). Accordingly, the report determined that to prevent abuses of this sort:

> [i]n the case of taxpayers who are operators, refiners, transporters, etc., the gross income from the property must be computed from the production and posted price of oil, as the gross receipts from a refined and transported product cannot be used in determining the income as relating to an individual tract or lease.

Id. at 12-13. The Joint Committ's thoughts were expressed in Treasury Regulation 74, Art. 221(i), promulgated pursuant to the Revenue Act of 1928. This regulation provided the following rule for computing gross income from a refined oil or gas product sold away from the wellhead:

> If the oil and gas are not sold on the property but are manufactured or converted into a refined product or are transported from the property prior to sale, then the gross income shall be assumed to be equivalent to the market or field price of the oil and gas before conversion or transportation.

Treas. Reg. 74 (1929 ed.), Art. 221(i). Slight amendments were made to this regulation in 1933 and 1936.

When the 1939 Internal Revenue Code was adopted, adjustments were made to the regulation once again, but the substance of the provision did not change.

With the statute and the new regulation in place, oil and gas producers could take percentage depletion deductions based on income generated by the property, with the income pegged to the value of the resource in its unrefined state at the wellhead. Producers of hard minerals were not allowed to take a similar deduction. The Treasury was hesitant to extend percentage depletion to mineral producers because it was even harder to determine the value of hard minerals in their unrefined state than it was to determine the value of unrefined gas. The Special Assistant to the Secretary of the Treasury discussed the administrative differences between oil and gas and hard minerals, stating that:

> [W]hile the bureau is having difficulty in administering the percentage depletion provisions in the case of oil and gas wells, the Treasury believes that the problem of administering like provisions in the case of mines would be infinitely greater. The foremost reason is that the field price of the oil or gas at the well indicates the income from the property, while in the mining industry, where there is no general field price for the ore at the mine and where the larger taxpayers do their own concentrating, smelting, refining, transporting, and marketing, all that is known is that the refined or fabricated product was sold for a certain amount. There is thus presented the insuperable difficulty of dividing up the resulting income among all those various activities—maketing,

> transporting, smelting, refining, mining, etc.—and then allocating the proper portion to the mining operation which would be the income from the mine.

Hearings before the Joint Committee on Internal Revenue Taxation, 71st Cong., 3d Sess. 111 (1930) (statement of B.H. Bartholow, Special Assistant to the Secretary of the Treasury).

Percentage depletion was extended to metal, coal, and sulphur mines in 1932. Revenue Act of 1932, ch. 209, § 114(b)(4), 47 Stat. 203. As with oil and gas properties, the deduction was to be calculated as a percentage of "gross income from the property." In Treasury Regulation 77, Art. 221(g), gross income was defined as:

> the amount for which the taxpayer sells (a) the crude mineral product of the property or (b) the product derived therefrom, not to exceed in the case of (a) the representative market or field price . . . or in the case of (b) the representative market or field price . . . of a product of the kind and grade from which the product sold was derived, before the application of any processes . . . .

Treas. Reg. 77 (1933 ed.), Art. 221(g).

The depletion deduction statute in effect in 1974 provided, in pertinent part:

> [T]he allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of the gross income from the property excluding from such gross income an amount equal to the rent or royalties paid or incurred by the

> taxpayer in respect of the property. Such allowance shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion.

I.R.C. § 613(a) (1954).

3. Treasury Regulation section 1.613-3

The relevant statutory provisions and regulations for the 1974 tax year which govern the present dispute have changed only slightly since the 1930s. For example, the limitation confining the deduction to fifty percent of "net income from the property" was changed to "taxable income from the property" in 1954. I.R.C. § 613(a). The governing language of section 613 was adopted by the Public Debt and Tax Extension Act of 1960. Pub. L. No. 86-564, 74 Stat. 290. Thus, for the 1974 tax year, the determination of gross income from oil and gas producing properties was made with reference to section 1.613-3(a):

> In the case of oil and gas wells, "gross income from the property," as used in section 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil or gas before conversion or transportation.

Treas. Reg. § 1.613-3(a).

The language of this regulation, governing the sale of oil and gas away from the well premises, did not change significantly for years. Still, there was some

concern that the RMFP of a produced resource could be greater than the price actually received by the producer for the resource under a pre-existing contract for sale, concerns that first arose in the 1920s. Recognizing that a field price could in fact be higher than a price based on actual revenues from off-premises sales, the Treasury promulgated a regulation, applying to hard minerals only, establishing a rebuttable presumption that such a market price is *not* representative. Specifically, section 1.613-4 (c)(6), put into its current form in 1972, provides:

> It shall be presumed that a price is not a representative market or field price . . . if the sum of such price plus the total of all costs of the nonmining processes (including nonmining transportation) which the taxpayer applies to his ore or mineral regularly exceeds the taxpayer's actual sales price of his product. . . . In order to rebut the presumption . . . it must be established that the loss on nonmining operations is directly attributable to unusual, peculiar, and nonrecurring factors rather than to the use of a market or field price which is not representative.

Treas. Reg. § 1.613-4(c)(6) (1972).

As is apparent, this regulation applies to hard minerals only, and not to oil and gas production. At one point the Secretary of the Treasury proposed extending the regulation to cover oil and gas as well, but the proposal was withdrawn, leaving the language in section 1.613-3(a) unchanged. 33 Fed. Reg. 10700 (1968); 36 Fed. Reg. 19256 (1971).

B. Natural Gas Production

Natural gas as it emerges from the wellhead is a swirling mixture of hydrocarbon gases and liquids with various other minerals and contaminants, such as water, water vapor, and may include sand, hydrogen sulfide, carbon dioxide, nitrogen and helium. Natural gas is composed primarily of methane with small amounts of heavier hydrocarbons such as ethane, propane, butanes, pentanes, and heavier components. Methane, the lightest component, is composed of one carbon atom and four hydrogen atoms. Ethane, the second lightest hydrocarbon component, has two carbon atoms. The hydrocarbon components of natural gas that contain five or more carbon atoms (pentanes, hexane, heptane, octane, nonnane and decane) are generally referred to collectively as "natural gasoline."

Natural gas is found in hydrocarbon accumulations in geologic traps called reservoirs. Natural gas exists in three conditions in reservoirs: 1) gas, without the presence of oil, 2) gas dissolved in oil, or 3) a gas cap over oil. When produced, natural gas is generally classified as "gas well gas" or "casinghead gas," depending upon its origin. "Gas well gas" refers to gas that is found in a gaseous state at reservoir conditions. Wells that produce gas well gas are called "gas wells." "Casinghead gas" refers to gas that was dissolved in oil at reservoir conditions but becomes gaseous at atmospheric pressure at the top, or "casinghead," of an oil well. Casinghead gas is generally richer in heavier hydrocarbons than gas well gas, and it is generally produced at lower pressure.

After a potential hydrocarbon trap or reservoir is located using seismographic or other geologic techniques, an exploratory well is drilled to confirm the presence of hydrocarbons. A gas or oil well is a hole that serves as a channel from the underground accumulation to the surface. The well is drilled by boring through the layers of soil and rock until the reservoir is penetrated. If a well successfully locates a reservoir that is economical to produce, the well is completed by running two or more strings of casing and cementing them in the hole. The casing extends to the surface where it connects to a series of fittings and valves known as the "Christmas tree" which regulates the flow of oil and natural gas from the well. Once the presence of commercial quantities of hydrocarbons is established by the discovery well, additional wells are drilled, as necessary, to optimally produce the oil or gas.

Oil and gas exist under pressure in the reservoir and they flow to the surface of the well due to expansion or pressure differential. Generally, initial reservoir pressure on the Gulf Coast is a function of the well depth. Most of the gas at issue in this case was produced from reservoirs at depths of 6,000 to 8,000 feet. A well's pressure is an indicator of its ability to flow gas to a pipeline. The ability of a well to flow gas is sometimes referred to as "deliverability."

Gas reserves are measured in part by determining a formation's pressure. Over time, as a reservoir is produced its pressure decreases. To sustain production, producers may install compressors to decrease the back pressure on a well as a reservoir nears depletion.

Condensate is recovered at the surface of a gas well as a result of condensation of the gas stream due

to reduced pressure or temperature of petroleum hydrocarbons that existed in a gaseous phase in the reservoir. Most of the natural gas in issue was processed to remove the heavier hydrocarbon components of the natural gas stream. The remaining gas stream, consisting principally of methane, is referred to as "residue gas." Natural gas containing significant amounts of hydrogen sulfide is generally referred to as "sour gas." Natural gas that is relatively free of sulfur constituents is called "sweet gas." The gas from the 482 properties in issue was generally sweet gas, therefore treatment for removal of hydrogen sulfide was minimal.

When natural gas is extracted from a well, it is part of a "mixed well-stream" that includes oil, water, sediment, and other impurities. The effluent of a well is sometimes referred to as the "full well-stream."

In order to make the raw gas marketable, gas producers undertake certain production activities. In gas purchase contracts, pipelines establish certain minimum "pipeline specifications" that gas must meet.[3] Gas meeting these specifications is commonly

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[3] Generally, pipeline specifications required that natural gas have a British Thermal Unit (Btu) content of at least 950 Btu per cubic foot, and contain no more than 1/4 grain of hydrogen sulfide and 10-20 grains of total sulfur per 100 cubic feet. The water vapor content was not to exceed seven pounds per million cubic feet (MMcf). The carbon dioxide content of the gas could not exceed two to three percent and the oxygen content was required to be one percent or less, the nitrogen content was limited to three to four percent, and one pipeline limited the presence of heavier hydrocarbons to 0.2 gallons per Mcf to minimize liquids condensing in the pipeline after delivery. For measurement accuracy, the maximum delivery temperature was limited to 120°F. Pipelines also set pressure specifications that typically required delivery

referred to as "pipeline quality gas." Most of the Exxon gas at issue met pipeline specifications after separation and dehydration.

In order to extract the raw gas from liquids in the full well stream, the full well stream is first transported from the well, through "flow lines," to a separator installed at or near the vicinity of the wellhead. Oil and free water are separated from the gas by the force of gravity. Gas, being lighter than oil or water, rises to the top of the separator vessel, while water and sediment, being heavier than oil, sink to the bottom and flow to a disposal facility. Oil and condensate (oil that existed in a gaseous phase in the reservoir), being heavier than gas but lighter than water, collect in the middle of the vessel and then flow to storage tanks called tank batteries.

After separation, raw natural gas produced in East Texas and the Texas Gulf Coast area generally contains water vapor in excess of pipeline specifications (seven pounds per million cubic feet (MMcf)). When gas is compressed or cooled, water vapor converts to a liquid or solid phase. Liquid water can accelerate corrosion and reduce gas transmission efficiency. Water in the presence of gaseous hydrocarbons can also form hydrates,[4] which can plug valves,

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at 800 to 1000 pounds per square inch (psi). These pressure figures represent the *maximum* pressure that a producer would be required to meet, but pipelines would permit delivery at lower pressure levels under certain circumstances.

[4] Hydrates are solid compounds that are formed from the reaction of free water, water vapor and natural gas. Hydrates resemble ice crystals and will cause a blockage in transmission lines by stopping the gas from flowing through valves and meters as the crystals build up. To prevent hydrates from forming, the transmission line temperature must be increased, the line pressure reduced, or the water and water vapor must be removed, usually by dehydration.

fittings and gas lines. Therefore, to reduce water vapor, the raw gas leaving the separator is then passed through a dehydrator. The most common dehydration process involves passing trimethylene glycol through the gas. A typical dehydrator is a vertical cylindrical tank. Gas enters the bottom of the tank and glycol enters the top and falls to the bottom. As the gas moves upward through the glycol, the glycol adsorbs the water vapor in the gas.

After dehydration, raw gas is transported through "gathering lines" to gas plants for processing. Gas processing involves the removal of the liquefiable hydrocarbons from raw or unprocessed gas. The liquefiable hydrocarbons in unprocesed gas, such as ethane, propane, butanes, and natural gasolines, are generally worth more if converted into liquid form and then separated into individual components. These liquid products are more easily transported and stored and they are used by chemical plants and refineries to manufacture plastics and other products. Exxon processed most of the gas in issue, at eight gas plants located at the King Ranch, Anahuac, Lovell Lake, East Texas, Hawkins, Katy, Pledger and Clear Lake Fields.

Raw gas entering a gas plant is first separated and dehydrated. Separation at the gas plant inlet recovers any condensate and water that was not recovered by the field separators, as well as condensate and water that condensed in the gathering lines. Dehydration is required at the gas plant because field dehydration, which typically reduces the water content of unprocessed gas to seven pounds per MMcf, is inadequate for gas plant operations, particularly those using low temperature processes to manufacture products. Low temperature processes, which

were typically used in 1974, require that virtually all water vapor be removed from the gas prior to processing. Gas plant dehydration, which may require refrigeration and absorption processes not generally used in field dehydration, is typically more carefully controlled and more expensive than field dehydration.

After separation and dehydration, the gas typically is cooled and enters an absorption tower where a light oil absorbs most of the ethane and heavier components. The light oil enriched with the liquefiable components is then sent to a still, where these components boil off, and the light oil is returned to the absorption tower. The component mixture from the still is piped to fractionation towers where it is separated into individual components of ethane, propane, iso-butane, normal butane and natural gasoline.

The various hydrocarbon components of natural gas can be combusted to produce heat. The amount of heat produced when gas is burned is measured in British Thermal Units (Btu's) and varies with the mix of molecule types in the particular natural gas. Generally, the larger the percentage of heavier hydrocarbon components in the gas the greater the Btu content of the gas. The heating value of one thousand cubic feet (Mcf) of natural gas at a standard temperature and pressure is typically 1 to 1.2 million Btu's (MMBtu). The volume weighted average Btu content of Exxon's gas was 1107 Btu per cubic foot. The hydrocarbon composition and Btu content of raw gas are not changed by dehydration or treatment to remove other contaminants. These processes merely remove impurities and prepare the raw gas for delivery to the pipeline.

Gas processing in 1974 was very profitable and contributed significantly to the value of the gas produced. The value of a rich gas stream would be much more than the value of a lean gas stream because the processing of the liquid products would increase the value of those Btu's by anywhere from sixty to one hundred percent. Generally, the higher the Btu per Mcf at the well head, the more valuable the gas is to the processor. The liquefiable hydrocarbons in raw gas, such as ethane, propane, butanes, and natural gasoline, are generally worth more if converted into liquid form and sold separately from the residue gas. These liquid products are used by chemical plants and refineries to manufacture plastics and other products. Liquid products such as propane and butanes are also used extensively for fuel and heating.

After natural gas has been processed, only the residue gas is sold as gas. This residue gas is sometimes referred to as "processed gas." It consists principally of methane, the lightest of the hydrocarbon components present in natural gas. Including the amounts used for fuel, ten to twenty percent of the heating value of the raw gas is typically consumed in the liquid extraction and fractionation processes in a gas plant. The volume shrinkage is somewhat less. As a result, residue gas typically contains fewer Btu's per cubic foot than unprocessed raw gas. Residue gas is transported through "transmission lines" to an end user.

In sum, "natural gas" or the "full well stream" refers to gas at the effluent of a well or gas before it is passed through a field separator. "Raw or unprocessed" gas refers to gas after it has been through a field separator but before it has passed through a gas

plant for the removal of liquefiable hydrocarbons. Raw gas, therefore, may also refer to gas that has been dehydrated, compressed and treated for removal of impurities such as hydrogen sulfide. "Residue gas" or "processed gas" refers to gas that has been processed for removal of liquefiable hydrocarbons.

In 1974, Exxon produced natural gas from approximately 5,000 wells on the 482 properties in issue. Of the 5,000, about 1,000 were gas wells and approximately 4,000 were oil wells that produced casinghead gas. Approximately eighty-five to ninety percent of this gas was produced from the 1,000 gas wells, while ten to fifteen percent of the total gas was produced from the oil wells.

The term "field" generally refers to a geographic area that overlays a single reservoir or multiple reservoirs. The size of individual fields may range from a few acres to several thousand acres. The terms "basin" and "embayment" are used to describe large areas containing many fields and hundreds of reservoirs.

The 482 properties at issue in this case are located in forty-six oil and gas fields in East Texas and along the Texas Gulf regions. The Texas Gulf Coast region consists of Texas Railroad Commission [5] Districts 2, 3, 4 and adjacent offshore areas. East Texas includes Railroad Commission District 6.

Of the 482 properties, 310 are in the East Texas Basin (in Railroad Commission District 6), and 172 are along the Texas Gulf Coast (Districts 2, 3 and 4). Exxon's 172 Gulf Coast properties are within the

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[5] The Texas Railroad Commission is the State agency with the legislative authority to regulate the production, transportation and resale of natural gas in Texas.

Houston Embayment, the San Marcos Arch, and the Rio Grande Embayment. The Houston Embayment includes Railroad Commission District 3 and the northern portion of District 2. The Rio Grande Embayment includes Railroad Commission District 4 and the Southern portion of District 2. Ninety-five percent of the volume of the gas at issue was produced from 172 properties located in the Gulf Coast (Railroad Commission Districts 2, 3 and 4). The remaining five percent came from the 310 properties located in East Texas (Railroad Commission District 6).

C. The Natural Gas Market

During 1974, and for many years prior to, Texas was the largest gas-producing state in the United States. The oil and gas industry remains a major part of the Texas economy. The industry consists of thousands of producers, ranging from "mom-and-pop" type wildcatters to major integrated oil companies like Exxon. During 1974, about thirty gas pipelines connected gas producers to consumers in the East Texas and Texas Gulf Coast areas.[6]

Natural gas was not a highly sought-after commodity until after the conclusion of World War II.

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[6] In 1974, the major companies buying and selling gas in the interstate market included United Gas Pipeline Company, Transcontinental Gas Pipe Line Co., Columbia Gas Transmission Corp., Tennessee Gas Pipeline Co., Trunkline Gas Co., Texas Eastern Transmission Corp., Florida Gas Transmission Co., and Natural Gas Pipeline Co. Intrastate pipelines included United Texas Transmission Company, Houston Pipe Line Company, Lo-Vaca Gathering Co., Lone Star Gas Co., Delhi Gas Pipeline Corp., Southwestern Gas Pipeline, Inc., and Channel Industries Gas Company.

Prior to that time, its demand was largely provincial, and it was primarily a by-product of oil production efforts. The drilling of wells specifically in search of gas production was not a significant factor up until the post war period. The war industries and subsequent demand for consumer products following the war brought about a nationwide demand for relatively cheap natural gas.

From the 1940s through the 1970s, gas transmission pipeline companies purchased pipeline quality gas from producers, from gatherers, from gas processing plants, and from other pipeline companies.

The late 1960s marked a rise in the demand for natural gas in Texas. Demand increased with population growth and the expansion of the refinery and petrochemical industry. The steady increase in demand for gas produced an imbalance between supply and demand because new natural gas discoveries had not kept pace with increased demand. The decline in reserves could be attributed principally to the fact that during the 1960s demand was met from existing reserves, with producers conducting limited exploration for new supplies. This was primarily a result of the fact that the Federal Power Commission [7] (FPC) had kept the price of interstate gas artificially low during the 1960s, discouraging drilling for new supplies.[8] As a result of stable low prices many producers,

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[7] The Federal Energy Regulatory Commission (FERC) replaced the FPC in 1977. Dept. of Energy Organization Act, 42 U.S.C. §§ 7101-7352; Exec. Order No. 12009, 3 C.F.R. 142 (1978); Administrative Procedure Act, 5 U.S.C. Ch. 5.

[8] Following the Supreme Court's decision in *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954), producers who sold gas to pipelines in the interstate market became

as well as pipelines reselling gas to consumers, entered into long-term, fixed-price contracts with minimal escalation provisions that anticipated a continuation of stable prices.

Market areas changed significantly during the late 1960s and early 1970s as heightened demand prompted pipelines to search for more natural gas supplies. Due to the costs of transporting natural gas, the market for gas produced from a given reservoir was defined by the pipelines with economic access to the reservoir. Economic access is a function of distance and reserves. During the 1960s, a reservoir with modest reserves was often unmarketable unless a pipeline was already in the immediate area. Even then, the pipeline might require contract provisions unfavorable to the seller and offer a below-market price.

By 1971, the buyers' market for gas had become a sellers' market. Interstate pipelines, restricted by the FPC in what they could pay for gas, were basically priced out of the market. The FPC responded by granting interstate pipelines authority to contract for temporary, emergency supplies at prices in excess of area rates, as well as to pay higher prices for newly discovered gas. These actions intensified the competition for available gas supplies. Intrastate gas prices, driven by booming intrastate demand and energy shortage paranoia fueled by the October 1973 Arab-

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subject to the jurisdiction of the FPC. Gas reserves committed to an interstate pipeline became interstate gas regardless of where the gas was sold. Identical gas, even if from the same field, sold to an intrastate pipeline remained unregulated. Producers were willing to accept prices about $.005 to $.01 per Mcf lower than the interstate prices in order to sell gas free of federal regulation in the intrastate market.

Israeli War, the ensuing Organization of Petroleum Exporting Countries (OPEC) oil embargo, and the Lo-Vaca Docket 500 filing,[9] doubled during 1973, and doubled again in 1974. Long-term, fixed-price contracts were no longer the norm, with new supplies being contracted under shorter term contracts, and existing contracts being amended in some cases to provide for periodic price adjustments.

The market for gas from reservoirs with small reserves improved in the early 1970s, but the more dramatic change occurred in the market for reservoirs with large reserves. When gas was in abundant supply, large reserves could be marketed to any pipeline with facilities near the production area. By the 1970s, however, substantial reserves located along the Texas Gulf Coast could be marketed to almost any pipeline in the Gulf Coast area.

Within a production area such as the Texas Gulf Coast or East Texas during the early 1970s, large reserves of gas could be sold at fairly uniform prices. Pipelines did not differentiate prices based on distance

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[9] A Docket 500 filing was somewhat the equivalent of a bankruptcy proceeding instituted with the Texas Railroad Commission under the supervision of the Texas courts. In the 1960s, the Lo-Vaca Gathering Company, like other pipelines in the industry, entered into long-term, fixed-price contracts to supply gas. By the early 1970s, Lo-Vaca's commitments exceeded its supplies, and the increased price for new gas supplies made it uneconomical for Lo-Vaca to obtain such supplies because it was committed to sell the gas for less than the market price. Lo-Vaca accordingly "curtailed" its customers, cutting their supplies which resulted in municipal power shortages. The end result of the ensuing litigation was that Lo-Vaca was held to its commitments under its long term contracts.

from market, or whether or not gas was processed, nor were there any quality differences that caused significant price differentiation for East Texas and Texas Gulf Coast gas.

In general, the more pipelines in a market area, the better the price and other contract provisions a producer could expect. In the early 1960s, Texas Gulf Coast pipelines were connected to East Texas pipelines. After that time, very large reserves on the Texas Gulf Coast or in East Texas could accordingly command the highest prices and most favorable terms in the entire Gulf Coast to East Texas area. By 1972, West Texas had been connected by pipeline to the Gulf Coast, and large reserves could command prices competitive with any other reserves in the state. Transportation and exchange agreements between pipelines also came into more extensive use in the early 1970s, with the result that the entire state ultimatey became the market area for large reserves. Gas from Exxon's King Ranch and Katy fields, for example, could have been marketed to most any pipeline operating in Texas.

Escalating gas prices meant that, by 1974, many producers could practically write their own deals. The primary factors affecting the price of natural gas in 1974 were: 1) the size of the reserves available for sale, 2) the presence of other pipelines in the area (competition), and 3) the time during the year in which the contract was negotiated. Pipeline companies were interested in reserve size and deliverability, whereas the producer was mainly interested in price and "take or pay" provisions. A "take or pay" provision required the purchaser to buy or pay for a stated percentage of the total deliverable volume pro-

duced. Such clauses benefit the producer by guaranteeing a minimum sale.

Another change in the industry was the shift in 1974, from Mcf-based to Btu-based pricing. This shift eliminated the distinction for pricing purposes, between processed and unprocessed gas. There were no premiums paid for high Btu content or for processed or unprocessed gas. Gas was considered gas and the only thing that mattered, other than reserve size and deliverability, was whether or not the gas met pipeline specifications. By 1974, intrastate pipeline companies typically sold gas to their consumers on the basis of their weighted average cost of gas (WACOG), plus a negotiable spread, usually $.05 per Mcf.

It was common in 1974 for the producer to reserve the right to process the gas for the recovery of liquid hydrocarbons prior to delivery. On large reserve packages, producers often had the right to process at a "mutually agreeable point" on the buyer's pipeline downstream at the point of delivery. These provisions had no effect on the negotiated price. If they were exercised, an adjustment was made for plant shrinkage occurring downstream of the points of delivery. This could either be in the form of reimbursement, if payment had been made at the wellhead for the full gas stream, or in the form of a reduction in the delivered volume, if payment was at the tailgate of the plant. In either instance, the price was the same per MMBtu sold.

The shortage of gas in 1974 resulted in pipeline companies offering concessions in addition to the highest price in order to get larger packages of gas. In addition to paying a high price, it was customary for pipeline companies to offer consideration such as price

upgrades on old contracts and interest free loans. For example, the Houston Pipe Line Company gave price upgrades to encourage additional exploration on dedicated acreage. Exxon, as a fully integrated producer, had its own pipeline system and thus was generally beyond the pale in this regard.

Gas purchase/sale contracts, in 1974, also featured most-favored-nation or price redetermination provisions whereby pipelines agreed to raise the price each month to the highest price being paid in the area.[10] During the early 1970s, price redetermination provisions were based on the highest prices in a particular Railroad Commission District for gas sold under "similar terms and conditions." However, by 1974, these clauses were broadened in scope to permit the redetermined price to be the average of the two or three highest prices being paid in Railroad Commission Districts 2, 3, and 4. Eventually, by 1980, some contracts stipulated that the redetermined price would be based upon the highest price being paid in the entire state of Texas.

While there is evidence that suggests otherwise,[11] the court finds by a preponderance of the evidence,

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[10] Price adjustment or redetermination clauses typically provided for periodic price adjustments to the highest (or the average of a number of the highest) prices paid in an area. Frequently, these clauses included "similar conditions" or "appropriate adjustments" provisions designed to account for variation between the subject contract's terms and the terms of the competing contracts that were identified in redetermining the price.

[11] For example, defendant argues that the characteristics of gas produced from Exxon's 482 properties are so different that they fall into at least two markets for each of which a

that by 1974 the entire Texas Gulf Coast and East Texas system should under the circumstances of this record be regarded as a unit; both a single supply area and a single market area. There was comparable gas available for sale throughout this area, and there was active competition for that gas across the area.

D. The Exxon Gas System & The TIC Contracts

Because of the magnitude of its natural gas production, in the 1930s Exxon built its own gas pipeline transmission system, now known as the Exxon Gas System (EGS). EGS was built to provide access for Exxon's large natural gas reserves to the industrial markets along the Texas Gulf Coast. EGS, which by 1974 had grown to a length of about 1500 miles, consisted of two primary interconnected lines: one line

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separate RMFP should have been computed: 1) the East Texas market with 310 of the properties in issue, which produced mostly high Btu casinghead gas from low pressure oil wells, and 2) the Texas Gulf Coast market with 172 of the properties in issue, which produced mostly low Btu gas-well-gas from high pressure gas wells. Exxon, as noted in footnote sixteen, *infra*, used three market areas for computing its Field Price, of which the Gulf Coast region had the highest prices. Designation of market area, however, is an *ad hoc* determination. The Court of Claims in *Panhandle Eastern Pipe Line Co. v. United States* stated that:

> *an all-inclusive rule* [to define the market area to be considered in computing RMFP] *cannot be laid down due to the fact that each case arises in its own particular context* depending upon the surroundings in which the individual taxpayer finds himself.

Id., 187 Ct.Cl. 129, 168, 408 F.2d 690, 714 (1969) (emphasis in original); quoting *Hugoton Prod. Co. v. United States*, 172 Ct.Cl. 444, 464, 349 F.2d 418, 431 (1965) (*Hugoton II*).

running from a point near Corpus Christi in South Texas to a point near Tyler in northeast Texas and a second line running from Houston toward the Louisiana border to Port Arthur.

EGS is supplied with processed gas from Exxon's eight gas plants. In 1974, Exxon's King Ranch and Katy Field gas plants supplied eighty percent of the total gas transported through EGS. The cost in 1974 of transporting gas through EGS, Exxon determined, was approximately five cents. The gas transported through EGS was produced from the 482 properties in issue.

To support the major capital commitment required for the extension of EGS, Exxon needed an assured market for its gas. Exxon secured that market by entering into long-term gas sales contracts, known as the Texas Industrial Commitments contracts (TIC). Most of the gas transported through EGS was sold under one of Exxon's TIC contracts. In this case approximately two-thirds of the gas in issue was sold under the seventeen TIC contracts. During 1974, seventeen of these long-term contracts were in effect obligating Exxon to deliver over eight trillion cubic feet (Tcf) of pipeline quality gas through 1984. The seventeen TIC contracts were entered in ten different years; the first contract in issue was entered in 1953 for a term of twenty years, the last in 1972 for a term of five years. Ninety-five percent of the gas Exxon delivered to its TIC customers in 1974 was "residue gas," *i.e.*, processed gas. The remaining five percent was pipeline quality gas made by dehydrating raw gas.

As noted, long-term, fixed-price contracts were typical in the industry during that time period when low,

stable natural gas prices were prevalent. When each of the seventeen TIC contracts was made, the price Exxon received for gas delivered to the TIC customer was higher per Mcf than the average price at which gas was then being sold. Although the price terms were favorable to Exxon when the TIC contracts were signed, not all of the contracts provided for market-based price adjustments, *i.e.*, most-favored-nation or price redetermination clauses (five had price renegotiation clauses, two had take or pay clauses), to reflect changes in the wellhead value of the gas.[12] The contracts, however, did include escalation clauses (usually providing for a $.01 increase every four years) reflective of an estimate of inflation.[13]

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[12] The record is not clear as to why Exxon did not include such provisions in all its TIC contracts, in light of the fact that such clauses apparently were common in such long-term contracts. For example, in *Hugoton*, which involved the tax years 1952-1957, the court found that "[t]he sellers, in order to protect themselves against future increases in prices, inserted in their contracts fixed periodic price escalation clauses, 'favored nation' clauses, and clauses providing for price renegotiations at fixed intervals." *Hugoton I*, 161 Ct.Cl. at 319, 315 F.2d at 894 (footnote omitted). It may be reasonably inferred that Exxon was aware of the practice by sellers of including such clauses and that it did not include these clauses because of what it believed at the time to be sound business considerations.

[13] Notably, other producers, such as Mobile, attempted to and were successful in renegotiating the terms of their long-term contracts. Exxon's expert in gas production, marketing and transportation, Jack Earnest, who from 1970 to 1975 was responsible for marketing Mobil's gas production in the United States and Canada, testified that possible inducements for renegotiation were offers of new gas supplies or offers of additional exploration and development to increase deliver-

The 482 properties in issue were the source for about eighty percent of all the gas that Exxon produced in Texas during 1974. During1974, the volume weighted average selling price of gas delivered under the seventeen TIC contracts was approximately $.23 per Mcf.

E. Exxon's 1974 Tax Return

Exxon calculated its "gross income from the property" for the gas sold from the properties in issue using its "Field Prices," which were weighted average prices calculated by reference to third-party pipeline company purchases of both processed and unprocessed gas. Exxon used the Field Price to establish the value of the gas produced from its leases or gas plants when it was used by Exxon in its own operations in a field or when it was delivered to the EGS for sale off the lease. The Field Price was used as a basis for calculating royalty payments, Texas gas production tax, and the sales price in arm's length transactions with third-party working interest owners.[14]

In determining Field Prices for 1974 the volume-weighted average prices were calculated for each

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ability. Buyers were often amenable to adjusting contracts in the hope of purchasing new gas supplies in the future. Earnest testified that Mobil, as well as other producers, had to "prioritize" their efforts to renegotiate all their contracts. In this way Mobil was able to obtain more favorable prices.

[14] A royalty interest is a right to oil and gas in place that entitles its owner to a specified fraction, in kind or in value, of the total production from the property, free of expense of development and operation. A working interest is an interest in oil and gas in place that is burdened with the cost of development and operation of the property.

calendar quarter based on data from the most recently field Forms 60-1.50, Purchasers' Monthly Gas Tax Reports, filed with the state of Texas by pipeline purchasers. Exxon analyzed these tax reports, which had been filed by fifty to sixty large pipeline companies as first purchasers of gas produced in Texas and represented over eighty-five percent of the gas produced in Texas during 1974.[15] Because the tax reports were not available until three to four months after the relevant pricing period, the monthly average industry prices were plotted and projected forward, based on a review by an Exxon management committee, to set the Field Price.

The Exxon Field Price for gas transported through EGS during 1974 ranged from $.24 to $.50 per Mcf. depending on the time of year (the Exxon Field Price was computed once a calendar quarter) and price area (South Texas, Gulf Coast, and East Texas).[16] For 1974. Exxon determined that the weighted average Field Price was $.30 per Mcf. It is important to

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[15] The first-sale market for gas is the market into which gas is first sold by producers. Producers typically sell gas to pipelines, gatherings companies, or gas plant operators in the first sale market. These purchasers in turn transport or process the gas, and resell it either to other pipeline companies, to natural gas distribution companies (municipal or private), or directly to industrial users.

[16] For 1974, Exxon established the following field prices per Mcf:

	1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
South Texas	$.25	$.28	$.30	$.33
Gulf Coast	$.29	$.32	$.40	$.50
East Texas	$.24	$.27	$.27	$.27

keep in mind that although Exxon's weighted average Field Price of $.30 per Mcf was used as an RMFP, it was calculated from processed as well as unprocessed gas and did not, nor was it intended to represent, the value of raw gas in the immediate vicinity of the well. The Exxon Field Price is the value of gas ready for delivery into a pipeline at the tailgate of a processing plant, which came after production of gas at the wellhead, separation, dehydration, compression, gathering, removal of crude oil, and liquefiable hydrocarbons. Other components of the full well stream removed at gas plants such as liquefiable hydrocarbons were valued separately. When the value of these other components (liquefiable hydrocarbons) is added to the residue gas value, the average amount claimed as "gross income from the property" on Exxon's 1974 tax return was $.36 per Mcf.

Having calculated the "gross income from the property," Exxon proceeded to calculate its allowable depletion deduction. On its 1974 consolidated federal income tax return. Exxon claimed depletion deductions totaling $170,094,205 with respect to the 482 properties in issue.

The parties stipulate that after an audit, the Commisioner of Internal Revenue (Commissioner) determined that Exxon, on its 1974 return, had overstated its total gross income from the property with respect to the 482 properties in issue by $50,253,856. The Commissioner arrived at the adjustment by reducing Exxon's total depletable gross income by the difference between: 1) an amount calculated by multiplying the weighted-average Exxon Field Price ($.30 per Mcf) by the total gas volume sold to Texas Industrial Commitment (TIC) contract customers, and 2) the amount Exxon received for gas sold to its TIC

customers (an average of $.23 per Mcf), less EGS transportation costs ($.018 per Mcf) yielding an average value of $.212 per Mcf. The Commissioner did *not* adjust the depletion deductions claimed for natural gas liquids or other gas produced from the 482 properties (approximately $.06 per Mcf), and not sold under the TIC contracts.

This methodology yielded a weighted average gross income from the property value (before subtracting royalties) for all gas produced from the 482 properties of $.30 per Mcf. As a result of this methodology, Exxon's depletion deduction decreased by $11,105,698, which resulted in an increase in Exxon's 1974 federal income tax liability in the amount of $5,330,734. The Commissioner, in effect, allowed approximately eighty-three percent of Exxon's requested depletion deduction.

It is also stipulated that the $.36 per Mcf from Exxon's 1974 tax return and the $.30 per Mcf that the Commisioner allowed as a deduction for the entire raw gas stream (residue gas and natural gas liquids) can be compared to Exxon's RMFP of $.41 per Mcf, defendant's RMFP of $.25, as well as defendant's net-back value of $.21 per Mcf.[17]

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[17] At oral argument, the parties agreed that the representative market or field price [RMFP] of $.41 per Mcf that Exxon now seeks is analogous to the following amounts: the $.36 per Mcf from Exxon's 1974 tax return, the $.30 per Mcf that the Commissioner allowed, defendant's alternative RMFP of $.25 per Mcf, and defendant's net-back value of $.21 per Mcf. This is not a valid comparison, because the $.41, $.25, and $.21 figures purportedly represent the wellhead price of unprocessed gas and therefore should not include any value for liquid hydrocarbons, whereas the $.36 from Exxon's 1974 tax return and the $.30 allowed by the Commissioner includes the gross income value of all raw gas *and* products of the raw

Additionally, the parties have stipulated that the audit was based on the Commissioner's assertion that for the purpose of a depletion deduction, "gross income from the property" cannot exceed actual total sales revenues.

II

As indicated above, the battleground for this litigation is the second sentence of section 1.613-3(a) which provides:

> If the oil or gas is not sold on the premises but is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price [RMFP] of the oil or gas before conversion or transportation.

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gas, including gas consumed as fuel, gas sold after separation and dehydration (including gas sold to Exxon's TIC customers), other dispositions of gas, and gross income from the property attributable to liquefiable hydrocarbons, totalling approximately $.06 per Mcf.

If, as the parties stipulate, these figures do indeed compare the same thing, *i.e.*, the entire raw gas stream (residue gas and natural gas liquids), then the $.41, $.25, and $.21 figures should each be reduced by approximately $.06 to represent only the price of residue gas. This would be necessary because, as noted in part I.A. of this opinion, the Commissioner did not adjust the deductions claimed for the natural liquids and other plant products that made up the remainder of the raw gas stream.

Moreover, if the Commissioner's $.30 per Mcf is equivalent to the RMFP figures presented by the parties (which presumably does not include gross income from gas products), then the parties' stipulation that the Commissioner's audit was based upon the assertion that "gross income from the property" cannot exceed actual total sales revenues, must also be incorrect.

Treas. Reg. § 1.613-3(a). Both parties take polar positions relative to interpreting this language. Exxon argues that the literal reading of Section 1.613-3(a) requires the use of the RMFP when, as in this case, gas has been converted and transported away from the premises before sale. Exxon contends that the RMFP must be used regardless of the taxpayer's actual income from the property; thus, it does not matter whether the RMFP greatly exceeds or falls far below taxpayer's actual income.

Moreover, Exxon asserts that the goal of section 1.613-3(a) is to find the constructive price that the taxpayer could have received for the gas as if the taxpayer had not been vertically integrated like Exxon, but was instead an independent producer that sold raw gas at the wellhead. Exxon claims that by following the methodology of *Hugoton I & II* and *Panhandle Eastern Pipe Line Co. v. United States*, 187 Ct.Cl. 129, 408 F.2d 690 (1969), the RMFP for the gas produced in 1974 is $.41 per Mcf. Exxon contends that $.41 per Mcf is the weighted average price derived from almost all 1974 wellhead sales of comparable unprocessed gas within Exxon's market area.

In sharp contrast, defendant maintains that for purposes of computing a depletion deduction, an RMFP in excess of taxpayer's actual income is *per se* unreasonable because, "gross income from the property" can never exceed a taxpayer's gross revenue from the depletable deposits in issue, not even by $.01 per Mcf. I.R.C. § 613(a).

The literal language of the regulation supports Exxon's interpretation. Defendant's simple axiom that no reasonable person would sell something for less than he expended in manufacturing has surface

appeal but its application in this case would require the court to read into the regulation a cap on RMFP, a determination that Congress did not itself impose. A simple answer to this quandary may be found in the basic depletion allowance statute. It provides in pertinent part for a "reasonable allowance for depletion . . . according to the peculiar conditions in each case . . . ; such reasonable allowance in all cases to be made under regulations prescribed by the Secretary or his delegate." I.R.C. § 611. Thus, the test, it seems to the court, is not whether the RMFP exceeds or is below the actual sales price of the gas but rather whether the RMFP is *reasonable* under the circumstances.

The court previously addressed this issue in its June 29, 1993 Order denying defendant's motions for judgment on the pleadings and summary judgment. In its Order, the court concluded that:

> The plain language of the statute provides that the deduction shall be based on the gross income from the property, and the regulation says that gross income shall be assumed to be the representative market or field price before conversion or transportation. . . . On balance, the conclusion that the regulation's plain meaning should prevail does not produce such an absurd result that it should be ignored or discarded.

Exxon Corp. et al v. United States, No. 660-89, slip op. at 22 (Fed.Cl. June 29, 1993).

The court's Order was an interlocutory decision, and as such, the court may reconsider it up until the entry of a final judgment. *Jamesbury Corp. v. Litton Indus. Products, Inc.*, 839 F.2d 1544, 1550 (Fed.Cir. 1988), *overruled on other grounds by A.C. Aukerman*

Co. v. R.L. Chaides Constr. Co., 960 F.2d 1020 (Fed. Cir. 1992); *see 1B James W. Moore et al., Moore's Federal Practice* ¶ 0.404[4.-1] (2d ed. 1993). Defendant asks the court to reconsider this issue.

In its Order, the court refused to accept defendant's absolute position that an acceptable RMFP can never exceed the sale price of gas. The court merely recognized that there may be instances when the RMFP can exceed actual income, and should be considered reasonable. In order to accept defendant's position, the court, in essence, would have to read into the regulation a cap on the RMFP or hold that the regulation as written is invalid whenever an RMFP exceeds the sales price.

The Supreme Court has held that, "[t]he cardinal principle of statutory construction is to save and not to destroy." *NLRB v. Jones & Laughin Steel Corp.*, 301 U.S. 1, 30 (1937). To this end "a court should seek to avoid construing a statute in a way which yields an absurd result and should try to construe a statute in a way which is consistent with the intent of Congress." *Hellebrand v. Secretary of Dep't of Health and Human Services*, 999 F.2d 1565, 1570-71 (Fed.Cir. 1993); *see also Black & Decker Corp. v. Commissioner*, 986 F.2d 60, 65 (4th Cir. 1993) (stating that regulations, like statutes, are interpreted according to the canons of construction). The court should try to read the regulation consistent with the statute. *See Smith v. Brown*, 35 F.3d 1516, 1526 (Fed.Cir. 1994) (citing *LaVallee Northside Civic Ass'n v. Virgin Islands Coastal Zone Management Comm'n*, 866 F.2d 616, 623 (3rd Cir. 1989) (observing that regulations must be construed to avoid conflict with a statute if fairly possible)).

In questions of statutory or regulatory construction, the starting point in every case is the language itself. *Johns-Manville Corp. v. United States*, 855 F.2d 1556, 1559 (Fed.Cir. 1988) (quoting *Greyhound Corp. v. Mt. Hood Stages, Inc.*, 437 U.S. 322, 330 (1978)). If the meaning of a statute or regulation can be discerned within its words and does not produce and absurd result, that construction should control, and no resort should be made to extrinsic aids such as legislative history. The Federal Circuit has expressed this directly with respect to tax law, stating that "[w]here the language is plain and admits of no more than one meaning the duty of interpretation does not arise and the rules which are to aid doubtful meanings need no discussion." *Henry v. United States*, 793 F.2d 289, 293 (Fed.Cir. 1986) (quoting *Caminetti v. United States*, 242 U.S. 470, 485 (1917)).

The plain meaning rule, however, does not preclude looking behind the literal terms of a statute if the lack of such an examination would "compel an odd result." The Supreme Court stated:

> As we said in *Church of the Holy Trinity v. United States*, 143 U.S. 457, 459 (1982): "[F]requently words of general meaning are used in a statute, words broad enough to include an act in question, and yet a consideration of the whole legislation, or of the circumstances surrounding its enactment, or of the absurd results which follow from giving such broad meaning to the words, makes it unreasonable to believe that the legislator intended to include the particular act."

> Where the literal reading of a statutory term would "compel an odd result," we must search for other evidence of congressional intent to lend the term its proper scope. "The circumstances of the enactment of particular legislation," for example, "may persuade a court that Congress did not intend words of common meaning to have their literal effect." Even though, as Judge Learned Hand said, "the words used, even in their literal sense, are the primary, and ordinarily the most reliable, source of interpreting the meaning of any writing," nevertheless "it is one of the surest indexes of a mature and developed jurisprudence not to make a fortress out of the dictionary, but to remember that statutes always have some purpose or object to accomplish, whose sympathetic and imaginative discovery is the surest guide to their meaning." Looking beyond the naked text for guidance is perfectly proper when the result it apparently decrees is difficult to fathom or where it seems inconsistent with Congress' intention, since the plain-meaning rule is "rather an axiom of experience than a rule of law, and does not preclude consideration of persuasive evidence if it exists."

Public Citizen v. United States, 491 U.S. 440, 455 (1989) (citations omitted). The facts of this case necessitate looking behind the plain meaning of section 1.613-3(a). Indeed, based on the "peculiar conditions" of this case, the plain meaning of section 1.613-3(a) could "compel an odd result" that would not comport with section 611's provision for a "reasonable allowance for depletion."

Exxon claims that the RMFP for the 482 properties in issue is $.41 per Mcf, an amount approxi-

mately $.18 per Mcf more than it actually received ($.23 per Mcf) for the sale of the residue, *i.e.*, processed gas in issue and $.11 per Mcf higher, for unprocessed gas, than its own Field Price of $.30 per Mcf for residue gas. As discussed earlier, the legislative history of the depletion deduction reflects Congress' concerns that the depletion deduction might be used to offset profits from other lines of business unrelated to the purposes for depletion and that integrated producers might be able to obtain a competitive advantage over non-integrated producers. The depletion deduction statute and regulation have been amended to prevent such abuses. Although the court stated in its previous Order that there is no "persuasive indication that Congress intended sales prices of the gas to be determinative or that sales prices constituted a ceiling above which no deduction could be allowed," applying an RMFP of $.41 per Mcf to the gas in issue would allow Exxon to base its percentage depletion on approximately $155,000,000 (861,410,975 Mcf from the 482 properties x $.18 per Mcf) in "gross income from the property" that was never actually realized. Under such circumstances, the court must proceed with the utmost caution in determining whether such a result constitutes a "reasonable allowance for depletion" as mandated by the statute.

Exxon maintains the language of the regulation is clear on its face. Because Exxon's gas is transported from the premises prior to sale, Exxon contends that "the gross income from the property shall be assumed to be equivalent to the" RMFP. Therefore, Exxon argues, it is immaterial whether the RMFP exceeds the actual sales price of the gas by $.01 or by $1 billion. Defendant argues that Exxon's reading of the

language, although literally correct, produces an absurd result such that the language must be read as containing a cap, *i.e.*, "the gross income from the property shall be equivalent to the" RMFP to the extent that the RMFP does not exceed the actual sales price of the gas. If, defendant argues, the RMFP exceeds the sales price by $.01 or more it cannot be an acceptable RMFP for purposes of computing a depletion deduction.

Defendant asserts that "in no case has any taxpayer ever been permitted to calculate its percentage depletion deduction on an amount in excess of its actual gross income." Defendant's statement is correct, but it is quite different to say that the RMFP can *never* exceed taxpayer's actual income. Defendant directs the court to *United States v. Henderson Clay Prods.*, 324 F.2d 7 (5th Cir. 1963); *Panhandle*, 187 Ct. Cl. at 129, 408 F.2d at 690; and *Exxon Corp. v. Commissioner*, 102 T.C. 721 (1994). The cases cited by defendant were decided, as this one must be, based upon the "peculiar conditions in each case," not by imposing a cap on the RMFP. I.R.C. § 611.

In *Henderson*, the taxpayer, an integrated producer of raw ball clay, manufactured and sold bricks for $8.75 per ton. Taxpayer proposed an RMFP based on sales of shredded ball clay (the first commercially marketable product of non-integrated clay miners) in the ceramics market, where the market price was $10.50 per ton. The Fifth Circuit determined that the disparity between the $8.75 for the brick and the representative price of $10.50 for shredded ball clay was due to the fact that the national market for shredded ball clay was relatively small compared to the market for brick, and thus requiring the few

shredded ball clay producers to incur costs for advertising, management, and research. *Id.* at 10.

The Fifth Circuit in *Henderson* held that the taxpayer must use the proportionate-profits method of computing depletion base when the price of raw ball clay was not representative because use of that price did not fulfill the statutory objective of estimating that part of the integrated producer's gross income which was attributable to the operation of mining. *Henderson*, 324 F.2d at 15. An RMFP of $10.50 per ton would have allowed taxpayer to take into account not only its permissible costs of mining, but also unallowable costs of manufacturing, research, and advertising. Because the taxpayer could not in fact have sold its clay for the proposed RMPF, the court held the proposed RMFP was unreasonable. *Id.* at 15. Thus, in *Henderson*, the proportionate-profits method, rather than the proposed RMPF, gave a closer approximation of taxpayer's gross income from its mining activities. The use of the proposed RMPF would not limit the taxpayer in *Henderson* to its income from the market product closest to the raw mineral. The *Henderson* court did not decide the issue, which is now before the court, of whether an RMFP can exceed the sales price of the depleted product.

In *Panhandle*, the Court of Claims rejected the use of the RMFP when the proposed RMFP was not the representative of a wellhead sale. Instead, the court used the proportionate-profits method. The taxpayer in *Panhandle* sold gas from fourteen wells at the price of $.325 per Mcf. Pursuant to the contract, the delivery poinnt for a portion of the production from one well was on taxpayer's lease near the wellhead. The balance of the production from this well and the pro-

duction from taxpayer's thirteen other wells was transported from the leases by the taxpayer for delivery to the purchaser at a location some thirty to forty miles away. The court allowed the use of $.325 per Mcf with respect to the portion of gas sold near the wellhead on the lease, but rejected that amount as the RMFP for the remainder of the production for which the taxpayer had received $.325 per Mcf after the gas was gathered, transported, and delivered away from the wellhead. The court reasoned that:

> [U]sing the market comparison method and making such a determination on the basis of the unusual facts existing with respect to the issue at hand would stretch to the breaking point the doctrine of the *Hugoton* and *Shamrock* cases, . . . and conflict with the basic objectives underlying the decisions therein; defeat the purposes which led to judicial approval of the market comparison method including the use of weighted-average prices; and produce a price that could not be reasonably and realistically considered *representative* of plaintiff's economic situation or a "representative market or field price" in any real sense of such term.

Panhandle, 187 Ct. Cl. at 171, 408 F.2d at 716 (emphasis in original). Again, *Panhandle* did not deal with the issue of whether an RMFP can exceed the sales price of a depleted product.

In *Exxon Corp. v. Commissioner*, the Tax Court was presented with the same issue now before this court, concerning Exxon's 1979 tax year. The Tax Court determined that notwithstanding the last sentence of section 1.613-3(a), Exxon's use for depletion

calculation of an RMFP that resulted in "gross income from the property" greatly exceeding actual gross income after gas was transported away from the wellhead, was unreasonable in light of the legislative history of and the purposes for percentage depletion. Accordingly, the Tax Court found the Commissioner's use of the net-back method to be reasonable. The Tax Court stated that:

> [T]he purpose for the RMFP method was to provide a means by which parties could ascertain what *portion* of the taxpayer's *proceeds* from the sale of transported gas were attributable to the wellhead cost. *Hugoton Prod. Co. v. United States*, 161 Ct.Cl. 274, 315 F.2d 868, 869 (1963). It clearly was not designed to create "income from the property" that far exceeded the taxpayer's proceeds, for this would allow a depletion allowance on income that may already have been attributable to a depreciation deduction, a result not indicated by the legislative history.

Exxon, 102 T.C. at 743-744 (emphasis in original). Noting that the Code provides for a "reasonable allowance for depletion" under the "peculiar conditions in each case," the Tax Court held that the particular facts of its case (a suggested RMFP five times greater than the actual sales proceeds from the sale of gas after it was transported away from the wellhead) made it unreasonable to use the RMFP. The Tax Court, however, declined to specifically hold section 1-613(a) invalid. The court stated:

> There may be particular situations in which it is reasonable based upon the "peculiar facts" to allow the use of the RMFP even where it exceeds

> the taxpayer's actual gross income. We are not prepared even to attempt to define such situations or to delineate for other cases where the use of the RMFP may or may not be unreasonable. We hold only that its use would be unreasonable here where the result of using RMFP's is five times the actual sales proceeds from the sale of gas after it was transported away from the wellhead.

Exxon, 102 T.C. at 744 n. 28. Defendant seeks to denigate this language by suggesting that the Tax Court, aware of the instant litigation, did not wish to impinge on the proceedings before this court. Because the determination of what is a reasonable RMFP is essentially an *ad hoc* effort, *i.e.*, dependent on the facts in each case, defendant's suggestion of improvident deference is, at best, presumptuous.

In sum, the court declines to hold that an RMFP can never exceed a taxpayers actual gross income. Hence, the remaining issues in the instant case are two: first, whether *Exxon* has established an acceptable RMFP; and second, whether such an RMFP was reasonable under the "pecliar conditions" of this case. Accordingly, we examine next the parties' contentions as to these two issues.

III

"It is well settled that in a tax refund suit there is a *strong* rebuttable presumption of the correctness of the determination of the Commissioner." *Mulholland v. United States*, 28 Fed.Cl. 320, 331 (1993) emphasis in original) (citing *Welch v. Helvering*, 290 U.S. 111, 115 (1933) and *Snap-On Tools, Inc. v. United States*, 26 Cl.Ct. 1045, 1055 (1992)). Gen-

erally, the plaintiff has the burden of rebutting this presumption. *United States v. Janis*, 428 U.S. 443, 440-41 (1976). "A tax refund suit is not a quasi appellate review of an administrative determination. In order to prevail, the taxpayer, in addition to showing the IRS action was arbitrary, capricious, or unreasonable, must prove the correct amount of the tax and resulting overpayment." *Hearst Corp. v. United States*, 28 Fed. Cl. 202 230 (1993).

The twin burdens of proving that the determination of a deficiency was incorrect and proving that the correct refund amount to which the taxpayer is entitled to still more difficult to meet when the disagreement with the Commissioner relates to a deduction. Deductions are a matter of legislative grace, not of right. *New Colonial Ice Co. v. Helvering*, 292 U.S. 435, 440 (1934); *Hearst Corp.*, 28 Fed. Cl. at 230. Exemptions and exclusions from taxable income should be construed narrowly, and a taxpayer must bring itself within the clear scope of an exemption, an exclusion, or a deduction. *Commissioner v. Jacobson*, 336 U.S. 28, 49 (1949); *see also Interstate Transit Lines v. Commissioner*, 319 U.S. 590, 593 (1943) (stating rule that an income tax deduction is a matter of legislative grace and that the burden of clearly showing the right to the claimed deduction is on the taxpayer).

In the instant case, the Commissioner declined to accept Exxon's price of $.30 per Mcf (for unprocessed gas) as the basis for computing the depletion allowance. Because this $.30 per Mcf figure was computed, in part, from sales of gas that had been transported and processed, the Commissioner's rejection of this figure was clearly correct. *See Panhandle*, 187 Ct.Cl. at 172, 408 F.2d at 717. That left the Commissioner

with the sales price of the gas derived from the TIC contract sales as the only basis available to compute the depletion allowance. Because the sales price obviously included transportation costs, the Commissioner deducted the same, or "net-backed," in order to arrive at a reasonable depletion allowance. This process was approved in *Panhandle*. *Id.* Defendant now embraces the Commissioner's determination although it initially frowned on it. At oral argument defendant asserted that the Commissioner's action was appropriate because there was no persuasive evidence of an RMFP and the application of a net-back procedure, whether perfect or not, was reasonable in the absence of an acceptable RMFP.

Exxon has not directly attacked the Commissioner's determination. Instead, Exxon concentrated on establishing that $.41 per Mcf was the correct RMFP. Thus, Exxon assumed that substantiating that RMFP, in and of itself, served to invalidate the Commissioner's determination and the presumption of correctness that accompanies the determination. The record in this case, however, shows that various estimated RMFPs are possible through the utilization of different approaches and the usage of different sales and financial data.

Exxon has the burden of showing that an RMFP of $.41 per Mcf is supported by the data it presented at trial and that this data persuasively demonstrates that the sales relied on reflect sales of unprocessed gas in the immediate vicinity of the wellhead. Even assuming that Exxon carried this burden, that in itself, does not mean its estimate must be accepted for the purposes of allowing a depletion deduction greater than that allowed by the Commissioner.

As the Court of Claims did in *Panhandle*, the court will view the entire factual record to determine if the RMFP proposed is a reasonable one. Such an RMFP could be rejected as "highly indigestible." *See Panhandle*, 187 Ct. Cl. at 171, 408 F.2d at 716. The RMFP must be set in a manner that best follows the statute and the regulation, but when the regulation produces a "highly indigestible" result, the court must attempt to find a better figure. The *Panhandle* court stated, "[t]he regulation requires the use of a 'representative market or field price,' *if* an acceptable price of such nature can be established. Neither the court's decision in [*Hugoton II*] nor the regulation requires the impossible, *i.e.*, the use of a price that cannot be determined *representative*, or as precluding us from applying some other formula that produces a fair result." 187 Ct.Cl. at 174, 408 F.2d at 717-18 (emphasis in original) (footnote omitted).

The determination of an RMFP is a difficult task. The Court of Claims so observed in *Hugoton I*. 161 Ct.Cl. at 280, 315 F.2d at 871. It is difficult because there is no clearly defined procedure for the parties or the court to follow. It is especially difficult in this case because Exxon uses some 2,228 transactions as the foundation for the RMFP it proposes. Exxon's position, simply stated, is that the RMFP is determined by calculating the weighted average price of all existing wellhead sales of "comparable gas." In contrast, defendant contends that the RMFP is determined by calculating the weighted average price of "comparable sales of comparable gas." The following factors to consider in comparing gas were enumerated by the Court of Claims: 1) volume of gas available for sale, 2) location or proximity of lease to pipelines, 3) hydrogen sulfide content, 4) Btu content, 5) de-

liverability of the wells, and 6) delivery or rock pressure. *See Hugoton I*, 161 Ct.Cl. at 320, 315 F.2d at 894-95; *Hugoton II*, 172 Ct.Cl. at 449-50, 349 F.2d at 420-21; *Panhandle*, 187 Ct.Cl. at 156, 219, 408 F.2d at 707. The evidence supports a finding that the gas in issue was comparable or superior to the gas sold in the market area applicable in this case.

As discussed below, there are practical difficulties involved in establishing a sample of transactions relating to wellhead sales because of the limited availability and accuracy of sources of relevant information concerning these sales. Moreover, in the gas industry, certain terms, such as "wellhead," have different meanings for different people, under different circumstances. Indeed, the parties to a gas sale often agree beforehand on the meanings of these terms because of their recognition of this lack of precision.

A. Exxon's Proposed RMFP of $.41 per Mcf

The aim of the RMFP calculation, argues Exxon, is to determine the prevailing price being paid throughout the market area to non-integrated producers at the point at which they sell the "first marketable product." Exxon also contends that the RMFP calculation relies upon "the price which is in fact being obtained" in the marketplace under "a fair selection" of existing contracts to determine an integrated taxpayer's "gross income from the property." One of the few things upon which the parties agree is that the RMFP was designed to place integrated taxpayers on a par with non-integrated, independent producers in their allowable depletion deduction. *Cannelton*, 364 U.S. at 89; *Henderson*, 324 F.2d at 15; Panhandle, 187 Ct.Cl. at 143-44, 408 F.2d at 700.

Exxon interprets Court of Claims and Tax Court precedents as requiring that the RMFP be determined using market evidence to compute the weighted average price being paid for comparable raw gas prior to transportation from the premises, under the mix of "wellhead sale" contracts in effect within the relevant market area during the tax year. *Hugoton I*, 161 Ct. Cl. at 274, 351 F.2d at 868; *Hugoton II*, 172 Ct.Cl. at 444, 349 F.2d at 418; *Panhandle*, 187 Ct.Cl. at 129, 408 F.2d at 690 and *Shamrock Oil & Gas Corp. v. Commissioner*, 35 T.C. 979, 1039-40 (1961), *aff'd*, 346 F.2d 377 (5th Cir. 1965). The court takes no issue with this view.

Exxon maintains that pursuant to section 1.613-3(a) the transactions used to compute an RMFP must satisfy two requirements: 1) the gas in those transactions must not have been "manufactured or converted into a refined product," and 2) the sale must have occurred before the gas was "transported from the premises." Within the industry, Exxon contends, the term "wellhead sale" is used as a shorthand term to describe such transactions, *i.e.*, sales of "unprocessed gas" in "the immediate vicinity of the well." Exxon further contends that "unprocessed gas" is gas that has undergone the normal field production activities necessary to produce the first marketable product. These field activities include separation, dehydration, compression and treatment to remove impurities. Thus, Exxon argues that the movement of gas during these activities is not "transportation" within the meaning of section 1.613-3(a). Exxon gives a broad interpretation to the phrase "immediate vicinity of the well." It asserts that the "immediate vicinity of the well" is not intended to be just a linear restriction but is instead meant "conceptually" to en-

compass all activities that are part of the production process.

At trial, Exxon's natural gas pricing expert, Jonathan E. Ellis, stated that in 1974, $.41 per Mcf was the RMFP for the gas in issue.[18] Ellis has been employed in the natural gas industry since 1980. He has worked with natural gas royalty owners, producers, pipelines, and commercial consumers on assignments involving: research about contracts, prices and practices in effect at various times and in various places; and consultation about the future implications of agreements, market trends and regulatory developments. His work generally involves a variety of gas sales contracts, gas purchase measurement data and the development and processing of the same. Cur-

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[18] In its post-trial brief, Defendant challenges, for the first time, the nature of Ellis' testimony. Defendant claims that Ellis did not offer an "expert opinion" of RMFP for raw gas produced from each of its 482 properties in 1974 prior to conversion, manufacture, or transportation. Instead, Defendant asserts that Ellis merely made the calculations Exxon told him to make. Rule 702 of the Federal Rules of Evidence provides:

> If scientific, technical, or other specialized knowledge will assist the trier of fact to understand the evidence or to determine a fact in issue, a witness qualified as an expert by knowledge, skill, experience, training, or education, may testify thereto in the form of an opinion or otherwise.

Fed. R. Evid. 702. Ellis was offered and testified without objection as an expert in natural gas sale pricing and contract. His report was received into evidence, likewise, without objection. Defendant, in fact, acknowledges that Ellis' RMFP estimate is an expression of his opinion. The court considers Ellis' conclusion that $.41 per Mcf was the appropriate RMFP in this case to be an expression of his opinion based on his experience in the national gas industry.

rently, Ellis is a Vice-President and principal in the firm Willis, Graves & Associates, Inc., consultants whose clients are primarily producers of natural gas. There is no indication that Ellis had ever previously rendered an opinion as to RMFP or that he had, prior to this case, any familiarity with the concept of RMFP.

Ellis' RMFP of $.41 per Mcf is based on his use of 2,228 transactions allegedly representing over ninety percent of the wellhead sales of comparable unprocessed gas within Exxon's market area encompassing 844 Bcf of gas. Of these 2,228 transactions, interstate sales represented a volume of 334 Bcf with a volume weighted average price of $.28 per Mcf. Intrastate sales represented a total volume of 510 Bcf at a volume weighted average price of $.50 per Mcf. When the interstate and intrastate transactions are combined, the result is a volume weighted average price of $.41 per Mcf. Defendant maintains that Ellis' RMFP of $.41 per Mcf is insufficiently supported, unpersuasive, and fatally flawed.

In preparing his report, Ellis states that he and his staff relied on 2,228 transactions of gas purchases compiled from the following data: 1974 gas purchase transactions reported by natural gas pipelines in their annual reports to the FPC (in the case of interstate pipelines) and the Gas Utilities Division (GUD) of the Texas Railroad Commission (in the case of intrastate pipelines); transactional data reported by lessees (natural gas producers) to the Texas General Land Office (GLO) for properties in which the State had a royalty interest; and gas purchase contracts and other documents supplied by Exxon, which correspond to the transactional data in the public record. Ellis also looked at natural gas quality data found in the public

record, in the files of the pipelines operating in the market area and in the report of Roland Pohler, Exxon's expert in petroleum engineering, and reviewed the reports of Exxon's other expert witnesses, Jack Earnest, Tom Liles, Jeff Buie and Durland Eakin. Additionally, Ellis reviewed data about the 1974 gas market in Texas as reported in widely used industry sources.

During 1974 the FPC required each interstate pipeline operating in the United States to file an annual report on an FPC Form 2. The Form 2 solicited information about the gas purchases made by the reporting pipeline, including the seller, the annual volume, the Btu content of the gas, the amount paid for the volume purchased, and the state and field or county where each purchase of natural gas was made. The reports document the cost per Mcf of gas purchased by the pipeline in each transaction. The 1974 FPC Form 2 required the reporting pipeline to classify each purchase transaction into one of several categories or "accounts" based on delivery point. These accounts, which were established by the National Association of Regulatory Utility Commissioners (NARUC), included "natural gas well head purchases" (Account 800), "natural gas field line purchases" (Account 801), "natural gas gasoline plant outlet purchases" (Account 802), and "natural gas transmission line purchases" (Account 803).

The FPC's Uniform System of Accounts defines Account 800 purchases as including:

> the cost at [the] well head of natural gas purchased from producers in gas fields or production areas where *only the utility's faciilties* are used

> in bringing the gas from the well head into the utility's natural gas system.

18 C.F.R. part 201, Account 800 ¶ A (1974) (emphasis added). Account 801 purchases include:

> the cost, at point of receipt by the utility, of natural gas purchased in gas fields or production areas at points along gathering lines, and at points along the utility's transmission lines within field or production areas, exclusive of purchases at outlets of gasoline plants includible in account 802 [natural gas gasoline plant outlet purchases], where *facilities of the vendor or others* are used in bringing the gas from the well head to the point of entry into the utility's natural gas system.

18 C.F.R. part 201, account 801 ¶ A (1974) (emphasis added).

Similarly, in 1974, Texas law required each operating pipeline to file an annual report with the GUD of the Texas Railroad Commission. The GUD annual report, like the FPC Form 2, includes a purchased gas cost section that provides details of the pipeline's gas purchase transactions. Although the GUD annual reports are similar to the Form 2 reports, the Texas Railroad Commission did not adopt the NARUC Uniform System of Accounts for categorizing transactions until 1976. Most intrastate pipelines, therefore, did not use the account designations in their GUD filings until 1977, although some used the NARUC distinctions in reporting their gas purchases in 1974.

Exxon asked Ellis to compute a price for raw gas sold in the immediate vicinity of the well based on the full range of arm's length contracts in effect in

1974, regardless of contract vintage. Thus, his analysis included contracts executed long before 1974 even though those contracts may reflect prices established under a completely different set of regulatory rate-making practices or market forces not reflective of the 1974 market. Exxon further instructed Ellis to base his price calculations exclusively on the prices received for the sale of gas prior to manufacture or conversion when sold in the immediate vicinity of the well and to include both interstate and intrastate sales in his analysis. Ellis understood "prior to manufacture or conversion" to mean gas that is sold prior to processing commonly conducted at a gas processing plant. Construing the phrase "in the immediate vicinity of the well" broadly, Ellis only excluded from consideration sales that took place at the tail gate of processing plants and resales of gas. "Wellhead" sales included those in which the delivery point was described as any of the following: at or near the well on the lease, at the outlet of a separator, at the outlet of dehydration facilities, or on the lease.

Ellis included in his RMFP calculation both Account 800 and Account 801 transactions and their GUD equivalent based on the assumption that there are no economic or operational differences between Account 800 and Account 801 transactions. To illustrate the validity of this point, Exxon asserts that the volume weighted average price of Account 800 sales was higher than the volume weighted average price for Account 801 sales ($.43 per Mcf versus $.40 per Mcf). This assertion is misleading.

It may be true that the overall volume weighted average price for both interstate and intrastate Account 800 sales was greater than that of both inter-

state and intrastate Account 801 sales. That comparison of volume weighted averages, however, belies the fact that the volume weighted average price of interstate Account 801 sales was $.06 per Mcf more than the volume weighted average price of interstate Account 800 sales ($.29 per Mcf versus $.23 per Mcf) and that the volume weighted average price of intrastate Account 801 sales was $.05 per Mcf more than the volume weighted average price of intrastate Account 800 sales ($.52 per Mcf versus $.47 per Mcf).

The overall volume weighted average price for interstate and intrastate Account 800 sales was higher than that of interstate and intrastate Account 801 sales because the volume of the higher priced ($.47 per Mcf) intrastate Account 800 sales (240 MMcf) greatly exceeded the volume of the lower priced ($.23 per Mcf) interstate Account 800 sales (48 MMcf). Additionally, the volume of the lower priced ($.29 per Mcf) interstate Account 801 sales (286 MMcf) was only slightly greater than the volume of the higher priced $.52 per Mcf) intrastate Account 801 sales (270 MMcf). Consequently, the disproportionate volume of intrastate Account 800 sales in relation to interstate Account 800 sales skews the average price between the two accounts. This obscures the fact that, for both interstate accounts and intrastate accounts, the average price for Account 801 sales was approximately $.06 per Mcf greater than the average price of Account 800 sales.

Likewise, Exxon's claim that there are no operational differences between the Account 800 and 801 classifications is without merit. The fact that the FPC deemed it necessary to draw a distinction be-

tween the two accounts is significant in itself. The distinction is that in Account 800 sales the *purchaser* transports the gas away from the wellhead; whereas in Account 801 sales, the *producer* transports the gas away from the wellhead. Thus, Account 801 transactions by definition are not true wellhead sales because the delivery point of the gas is away from the wellhead. In essence, Account 800 sales reflect sales made at the wellhead and Account 801 sales reflect sales made at some other location. It is reasonable to infer that the difference in price between an Account 801 and an Account 800 transaction is due, in part, to the fact that the producer incurs costs for transporting the gas away from the wellhead.[19] Accordingly, the court is persuaded that there is a significant difference between transactions classified as Account 800 and those classified as Account 801.

Defendant argues that Ellis' study is unreliable because he failed to document adequately at least half of the transactions from which he computed the RMFP. In essence, defendant contends that Ellis should have restricted his database to transactions for which he had actual contract files. For the 2,228 transactions, Ellis obtained 600 contract files relating to approximately 1,164 transactions. Exxon asserts that such additional documentation is not required. In defense of Ellis' study, Exxon cites *Panhandle* for the proposition that:

> [It would be] impractical to go behind the [pipeline annual reports] in a comprehensive manner

[19] Earnest, Exxon's expert on gas production, marketing, and transportation, testified that the rate for transporting gas anywhere in Texas during 1974, was $.10 per Mcf.

> because this would require an unduly time-consuming and burdensome examination of all purchase contracts listed in the gas purchase sections of the forms. . . . It would be better, in any future litigation of this same kind, if the parties relied solely upon information contained in said forms.

Panhandle, 187 Ct.Cl. at 151-52, 408 F.2d at 704-05. An important difference between *Panhandle* and this case, however, is that in *Panhandle* the parties agreed on both the area from which comparable sales were derived and the sales (with limited exceptions) that were used in the computations.

The circumstances of the instant case differ dramatically from those in *Panhandle*. In the instant case, the parties do not agree on the relevant sales for the computation of the RMFP. Because of the "peculiar conditions" of this case, in which Exxon proposes an RMFP in excess of its actual income, the court concludes that the sales used must undergo greater scrutiny to insure that the RMFP is based on a "fair selection of contracts." *See Hugoton I*, 161 Ct.Cl. at 289, 315 F.2d at 877. The fact that Ellis has included 2,228 transactions allegedly accounting for over ninety percent of all unprocessed gas sold in Exxon's definition of the "immediate vicinity of the well," does not in itself engender confidence that the resulting RMFP is actually based on a fair selection of contracts of gas sold in the "immediate vicinity of the well."

Further, at oral argument, Exxon stated that the only way to put the integrated producer on the same playing field as the non-integrated producer, is "to look at what the non-integrated operators are selling

the production for." Exxon represented that "[t]he Ellis transactions, those are non-integrated. If you look at the list of the companies that are involved in the Ellis study and look at the names of those companies, you are going to be able to tell that those are very small operations. They are the Farmer Browns." Contrary to Exxon's representation, the list of transactions included in Ellis' study is, in fact, replete with sales made by large integrated producers such as Exxon, Mobil, Amoco, Gulf, Getty, Sun Oil, and Shell Oil.

As noted, Exxon broadly construes the phrases "immediate vicinity of the well" and "wellhead sales." The sheer number of transactions and the lack of adequate data as to each transaction leaves the court unable to ascertain whether the sales truly are sales of raw gas in the immediate vicinity of the well.

Exxon nevertheless maintains that the very size of Ellis' sample leaves little doubt that the RMFP was computed from a fair selection of sales transactions that are representative of the prevailing market conditions in the Texas Gulf Coast and East Texas region during 1974. Exxon cites *Hugoton* for the proposition that a large sampling of comparable transactions provides "greater assurance that the price derived is in fact representative." 161 Ct.Cl. at 289, 315 F.2d at 877. Exxon also observes that the *Panhandle* court emphasized "[t]he desirability of an adequate sample so as . . . to make more certain that any price computed is representative." 187 Ct.Cl. at 155, 408 F.2d at 706. Although a large sample can be more representative, it would be so only if there was some certainty that the sample transactions were "comparable sales" relative to sales in the imme-

diate vicinity of the well. The totality of the record suggests that the 2,228 sales include not only sales of gas away from the immediate vicinity of the well, but also some sales of gas that was dehydrated and compressed prior to sale as well as gas that was sold after being transported from the wells.

Moreover, the court, like the Tax Court in *Shamrock*, deems it:

> necessary to determine whether there are in evidence a sufficient number of actual sales of raw gas at the well from which we can find first, that there was a market for raw gas at the well and second, what the price in that market was for the years in issue.

Shamrock, 35 T.C. at 1034. The *Shamrock* court restricted its RMFP calculation to contracts which called for the receipt of the purchased gas at the well mouth, because "these contracts are relevant evidence of the [RMFP] of raw gas at the well mouth for the reason [that the objection] that the price shown may include *transportation, compression, or other costs* cannot, it appears to us, extend to the purchases of raw gas at this point." *Id.*, at 1037 (emphasis added). The court finds that the large number of transactions used in the instant case hindered rather than helped the determination of the correctness of Exxon's proposed RMFP. There is simply no way that the court can determine that all of these transactions represent sales of gas in the immediate vicinity of the well.

As stated earlier, Exxon contends that the RMFP is properly calculated based on sales of the "first marketable product." Accordingly, Ellis included

sales of gas that may have been dehydrated and compressed in order to meet pipeline specifications. Defendant concedes that the separation of oil, free water and condensate is an ordinary production activity, but disputes Exxon's contention that the subsequent dehydration of the gas in issue does not constitute "manufacturing or conversion."

The court finds conflicting the parties' evidence as to whether dehydration undertaken to meet pipeline specifications constitutes a typical production function performed by producers or whether it is a value-adding processing activity. Exxon asserts that dehydration is recognized within the industry as a typical production function that costs only $.0025 to $.005 per Mcf. Dehydration, Exxon contends, is viewed by the industry as the producer's responsibility because it is easier and more economical for the producer to perform these activities due to the producers' land-use rights and technical staff who monitor wells and coordinate the pumping, separating, and dehydrating of gas.

The evidence in the instant case, however, reveals that dehydration was not undertaken in every transaction by producers and that responsibility for dehydration was often a matter resolved by contract. For example, the Lo-Vaca Gathering Company, in some instances, would buy and take delivery of undehydrated gas immediately after initial separation along the Texas Gulf Coast. Additionally, the Houston Pipe Line Company, in an effort to encourage additional exploration on dedicated acreage, in some instances, took delivery of gas at the separator.

Defendant argues that all post-separation activity is a value-added activity beyond ordinary production

methods. Ordinary production methods are purely mechanical in nature, any method that is exclusive of fractionation, refrigeration, adsorption or absorption. Because dehydration is accomplished by the injection of a chemical, trimethylene glycol, defendant maintains that it is not an ordinary production activity.

While the issue is an extremely close one, and the record is conflicting, the court is persuaded by defendant's expert, Forrest A. Garb. Garb served as an expert witness *on behalf of* American oil companies before the Iran-United States Claims Tribunal in the Permanent Court of Arbitration, The Hague, Netherlands. Garb persuasively testified that ordinary production methods are purely mechanical in nature, and thus dehydration is not an "ordinary production activity."

There is support for Garb's position in the authorities cited by Exxon as precedents for determining the RMFP. In *Hugoton*, *Panhandle*, and *Shamrock*, the courts considered as comparable sales only sales of raw gas delivered to the purchaser at the wellhead or separator. *Hugoton I*, 161 Ct.Cl. at 274, 315 F.2d at 869, *Panhandle*, 187 Ct.Cl. at 150-51, 227, 236; *Shamrock*, 35 T.C. at 898. Indeed, plaintiff in *Hugoton* was assessed with a deficiency based upon an administrative determination that dehydration was a nonproducing rather than a producing function. *Hugoton I*, 161 Ct.Cl. at 316, 315 F.2d at 892.[20]

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[20] Exxon cites Proposed Treasury Regulation § 1.613-3 (a) (2), 33 Fed. Reg. 14707 (Oct. 2, 1968) for the proposition that the IRS at one time believed that separation and dehydration do not constitute conversion. This proposed regulation, however, was subsequently withdrawn and the court

Exxon, however, argues that limiting comparable sales to those where delivery was made at the wellhead or separator, would make section 1.613-3(a) largely irrelevant to modern gas production. That is, the cited cases involved gas production during the years 1943 through 1957 and field dehydration of gas by producers did not even occur in the industry before 1948, and was uncommon for some time afterwards. On the contrary, it is reasonable to infer that because field dehydration of gas was not common when Congress provided for the depletion allowance, Congress intended that the depletion allowance should be based on the value of the gas at the mouth of the wellhead or at the separator.

Exxon cites *Brea Cannon Oil Co. v. Commissioner*, 77 F.2d 67, 70 (9th Cir. 1935), *cert. denied*, 296 U.S. 604 (1935) as support for its contention that dehydration is a production process simply removing an impurity from the well stream (water vapor in the case of dehydration as compared to liquid water in the case of separation). In *Brea*, however, the court noted that the dehydration of oil merely involves the operation of gravity, a mechanical or "settling" process. *Id.* Unlike the dehydration of oil, the dehydration of gas involves the removal of water vapor through a chemical process.

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accords it little weight here. 36 Fed. Reg. 19,256 (1971). If the court were to accept Exxon's conclusion that defendant's present "position is inconsistent with the public position taken by the Internal Revenue Service," the court would also have to accept that the proposed and later withdrawn regulation presuming that a price that is in excess of actual revenue is not a representative market or field price. *See supra* p. 8 of this opinion.

Additionally, Exxon misplaces its reliance on *Cannelton* for the use of the "first marketable product" as the starting point for determining an RMFP. The Supreme Court in *Cannelton* stated that "Congress intended to grant miners allowance based on the constructive income from the raw mineral product, if marketable in that form . . ." *Cannelton*, 364 U.S. at 86. The Court, however, was interpreting the percentage depletion rules for hard minerals rather than the percentage depletion rules for oil and gas.[21] The rules for percentage depletion of hard minerals specifically include in gross income both income attributable to the extraction of the ores or minerals from the ground and the application of "ordinary treatment processes." *Id.* at 84-85, n.8. Neither sections 611 and 613 of the Code, nor section 1.613(a) of the Regulations include, as gross income from the property, income from enhancements by "ordinary treatment processes." Nor do these provisions make any allowance for transportation.

Moreover, Exxon's use of the "first marketable product" as its starting point casts doubt on just how

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[21] The rules for percentage depletion for hard minerals provided that gross income from mining included:

> not merely the extraction of the ores or minerals from the ground but also the ordinary treatment processes normally applied by mine owners or operators in order to obtain the commercially marketable mineral product or products, and so much of the transportation of ores or minerals . . . from the point of extraction from the ground to the plants or mills in which the ordinary treatment processes are applied thereto as is not in excess of 50 miles. . . . [specific listing of "ordinary treatment processes"].

I.R.C. § 114(b)(4)(B) (1939).

many of its 2,228 transactions really represent sales of gas in the "immediate vicinity of the well." Exxon's assertion that the phrase "immediate vicinity of the well" is not intended to be just a linear restriction but is instead meant to encompass all procedures that are part of the production process, is without support in case law or otherwise.

As discussed above, the cases cited by Exxon compute the RMFP from sales made at the "well mouth" or at the "wellhead or separator." Indeed, a factor in the Tax Court's decision in *Shamrock* was the distance the gas was transported before sale. The Tax Court noted that because the taxpayer's raw gas was produced from many different wells ranging in distance from less than one mile to more than twenty-five miles from the gas extraction plants where the gas was sold, the taxpayer did not sell raw gas in the immediate vicinity of the well. *Shamrock*, 35 T.C. at 1030.

The court concludes that computing the RMFP, and thus the "gross income from the property," based on sales made at the wellhead or separator is consistent with the philosophy behind the allowance for the depletion deduction. As the Supreme Court stated in *Cannelton*, "[d]epletion . . . was designed not to recompense for costs of recovery but for exhaustion of mineral assets alone." 364 U.S. at 88; *see also Brea*, 77 F.2d 67, 69 (1935) (stating that depletion allowance is intended to represent amount of capital recovered in the product by the well); *Consumers Natural Gas Co. v. Commissioner*, 78 F.2d 161 (2nd Cir. 1935) (holding that the "basis" for depletion is income from the wells, not from the oil or gas after it has been transported); *Greensboro Gas Co. v. Commissioner*, 79 F.2d 701 (3rd Cir. 1935) (same).

Although, for the gas in issue, dehydration was the rule rather than the exception, the court finds no indication that Congress intended to include dehydration or other such activities as "gross income from the property" for depletion purposes as was done for hard minerals. *See supra* note 21. Not all gas that is transported by a pipeline has to be dehydrated. The fact that virtually all the gas in the Texas Gulf Coast and East Texas area required dehydration (an operating procedure beyond mechanical separation) and that dehydration is commonly performed in this area, does not persuade the court that the RMFP should include the price of gas sold after dehydration.

Exxon asserts, however, that if Ellis restricted his database to sales of non-dehydrated gas the RMFP would increase. Exxon alleges that limiting Ellis' database to sales of non-dehydrated gas yields an RMFP of approximately $.49 per Mcf, $.08 per Mcf more than the proposed RMFP of $.41 per Mcf which includes sales of dehydrated gas. This fact further illustrates the need in this case for a greater scrutiny of the transactions included in the RMFP computation. Because Exxon's own evidence shows that dehydration costs range from $.0025 to $.005 per Mcf, it is counter intuitive and highly suspect to have a result where non-dehydrated gas costs more than dehydrated gas.

Ellis' opinion of the RMFP rests on his database of 2,228 sales. The court is not persuaded that even the bulk of these sales meet the criteria for an RMFP determination. The 2,228 transactions constitute a large sample, but the analysis of these transactions was minimal and Ellis' testimony failed to persuade the court that the proposed RMFP of $.41 per Mcf is

based on sales of raw gas in the immediate vicinity of the well. *See Arundel Corp. v. United States*, 207 Ct.Cl. 84, 99 (1975) (stating that "even uncontradicted opinion testimony is not conclusive if it is intrinsically nonpersuasive"). Ellis' RMFP of $.41 per Mcf most probably includes sales in which gas was delivered after transportation from the wellhead and after dehydration. Inasmuch as the evidence does not preponderate that the proposed RMFP is based on sales in the immediate vicinity of the well, the court concludes that the RMFP is not representative of the depletion of the gas alone. The court is unable to extract from the 2,228 sales proffered by Exxon those sales clearly established to be gas sales in the immediate vicinity of the wells.[22]

The vastness of Exxon's sample hindered rather than helped the court determine the accuracy of the proposed RMFP. A reasonable number of sales that had been sufficiently analyzed to demonstrate that the sales constituted a "fair selection of contracts" appropriate for RMFP determinations, would have been more persuasive. Therefore, the court concludes that Exxon has not met its burden of proving by a preponderance of the evidence that $.41 per Mcf is an acceptable RMFP based on the facts in this case.[23]

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[22] Defendant suggests that only forty-three of Ellis' 2,228 sales actually represent sales of gas that was not dehydrated or compressed prior to sale. Of these forty-three sales, only fifteen have corresponding gas purchase/sale contracts. For eleven of the fifteen sales, defendant contends, the contracts indicate that the delivery point may have been other than at the wellhead or separator.

[23] Another factor bearing on the unacceptability of Exxon's proposed RMFP of $.41 per Mcf. is Exxon's 1974 weighted average Field Price of $.30 per Mcf, a difference of $.18 per

B. Defendant's Submissions

At trial defendant submitted two separate determinations for the depletion value of the gas in issue. First, through the testimony of Processor Paul W. MacAvoy, defendant asserted that the proper and correct RMFP derived from Ellis' database is $.25 per Mcf rather than $.41 Mcf. Second, if the court holds that a reasonable RMFP cannot be determined, defendant proposes a net-back from Exxon's sales proceeds to the wellhead or separator which yields a figure of $.21 per Mcf.

1. Defendant's RMFP

MacAvoy testified for defendant as an expert in the field of economics including natural gas, natural gas markets, natural gas pricing and pricing issues in markets. Currently Dean and Williams Brothers Professor of Management Studies at the Yale School of Management, MacAvoy's career has included working

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Mcf. It is important to keep in mind that this Field Price included sales of both processed and unprocessed gas. The RMFP of $.41 per Mcf that Exxon now submits to the court is touted as the price for unprocessed gas. As discussed earlier, Exxon, presumably, used the Field Price of $.30 per Mcf as the RMFP for the purpose of calculating the amount of its depletion deduction in filing its 1974 tax return. In determining its Field Price Exxon ostensibly strived to arrive at a figure that was representative of the price at which gas was sold in 1974. Exxon downplayed the use of its Field Prices by suggesting that they lagged behind the actual prices for each calendar quarter in 1974. The evidence, however, shows that an Exxon management committee established its Field Prices by *plotting and projecting forward* from the monthly averages or industry prices. *See supra* p. 17 and note 16 of this opinion.

on policy problems in the energy, transportation, and communications industries. He has testified before the Federal Energy Regulatory Commission a number of times on gas pricing and transmission issues, and has testified before Congress on gas pricing. He served as a staff economist on President Johnson's Council of Economic Advisors during 1965 and 1966, and was a member of President Ford's Council of Economic Advisors during 1975 and 1976. There is no evidence in the record that MacAvoy had rendered previously, an opinion as to RMFP or that he was, prior to being consulted on this case, familiar with the concept of RMFP.

MacAvoy was asked by defendant to examine the method Ellis followed in computing the RMFP of $.41 per Mcf. MacAvoy's understanding of RMFP is based on his reading of the *Hugoton* and *Panhandle* decisions and of what representativeness in price means in economics, which in his own words is:

> in effect, a comparable price from an "as if" condition. It is as if Exxon had taken this gas and put it in the market at that time, in that location for sales at the wellhead to gatherers or pipelines, or commercial or industrial customers who may have facilities to burn it in a near location.

Thus MacAvoy asserts that Ellis' study is flawed because he calculates an RMFP using a set of contracts that are neither valid alternatives to Exxon's seventeen TIC contracts, nor are they comparable to each other. The contracts that Ellis averages together, alleges MacAvoy, result from different supply and demand conditions and are from different markets. Because a market has three dimensions; product, geography, and time, only those products which, from

the perspective of consumers, are reasonably interchangeable are in the same market; further, similar products have to be at geographic locations where, after accounting for transportation costs, there are reasonably similar price offers. Finally, as tastes, preferences, and technology change over time, so too will the interchangeability of products; thus goods sold at widely different times will be different, contradicting that they are in a common market.

MacAvoy contends that a contract for the sale of gas entered into in 1974 for $1.25 per Mcf is not comparable to gas produced in 1962 unless taxpayer had decided not to sell in 1962, but to hold those reserves out of the market until 1974 when it would put them into the market in competition against the new gas on the market. This is based on his premise that a producer must develop its reserves within a five-year period after discovery or face problems with royalty owners or risk having the reserves drained by neighboring producers. Once a producer commits its reserves and production begins, that producer is out of the market, therefore, MacAvoy argues, "it is terribly important that the comparisons to the TIC contracts be the commitments of new reserves made in the same year that the TIC contract was made or in surrounding years in the same market time period."

MacAvoy estimated the RMFP in 1974 for gas Exxon sold to its seventeen TIC customers using two distinct methods and a simulation exercise to check the correctness of the two methods. MacAvoy's approach for determining the RMFP posits a set of conditions required to make large numbers of actual market contracts of other suppliers comparable to the seventeen TIC contracts in issue. Contracts signed at different times or for reserves in different geographic

areas are adjusted to make them reflect the same supply and demand conditions as when Exxon entered into the seventeen TIC contracts. Only "representative" contracts drawn from the same market (defining market as limited by location, quality, and time), can be meaningfully combined to determine market price. Therefore MacAvoy established the RMFP of $.25 per Mcf for Exxon's gas from a sample of the Ellis contracts that he has attempted to make identical on average to each of the TIC contracts, and then determine the value of that alternative contract. MacAvoy did not examine Ellis' sample to determine if the transactions were wellhead sales; instead he accepted Ellis' transactions at face value, assuming it would appear that all were appropriate sales of gas in the immediate vicinity of the wellhead.

The first method used by MacVoy, his so-called "warm-up exercise," groups gas purchase or sale contracts signed during time periods two years before and two years after as well as the actual year that each of the seventeen TIC contracts was signed. Using transactions selected from the 2,228 included in Ellis' study, MacAvoy then gathered volume and price data for the 647 transactions for which a dated contract was available and which was entered into within the applicable five year time frame. For each TIC contract, he calculated the volume weighted average selling price for gas under the contracts selected from Ellis' database. Because the seventeen TIC contracts were entered in ten different years, ten samples were formed. He then calculated an overall volume weighted average price for 647 gas sale transactions grouped in five year periods with all seventeen TIC contracts

which equaled $.244 cents per Mcf, prior to netting out any relevant processing and transportation costs.[24]

Similarly, MacAvoy's second method of estimating an RMFP yielded an amount of $.245 cents per Mcf. In reaching this amount MacAvoy used a regression analysis whereby price averages are adjusted for differences in contract terms and conditions.[25] Essential to MacAvoy's procedures are the actual sales contracts. To make this evaluation it is necessary to have information for contracts, on distance to the field, gas volume, the time length of the contract, and provisions such as most-favored-nation price readjustments and price renegotiations. His regression analysis indicates that four of these variables have a significant effect on price; term of contract, age of contract, most-favored-nation clause, and interstate or intrastate sales. MacAvoy used data from 439 contracts which he identified as being in the same market as gas Exxon sold under each of its seventeen TIC contracts. Using his regression analysis with respect to each of the seventeen TIC contracts resulted in seventeen market prices. The volume weighted average of the seventeen prices is $.245 per Mcf.

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[24] It is not clear from the record why, if MacAvoy is assuming for purposes of his computations that the contracts in Ellis' study are wellhead sales of unprocessed gas, any processing or transportation costs need netting out.

[25] The following variables were used in his regression analysis: the term length of the contract; the volume of gas under commitment; the distance of the gas from final customers; the age of the contract; the presence or absence of a most-favored-nation clause; the presence or absence of a price renegotiation clause; the presence or absence of a take-or-pay provision; and whether the gas sales were for interstate or intrastate delivery.

MacAvoy's warm-up exercise, and to a greater extent his regression analysis, are based on his understanding that the *Panhandle* and *Hugoton* decisions require the use of contracts that are comparable to each of the seventeen TIC contracts in issue. "Comparable," MacAvoy contends, is a word keyed to the alternative available to the producer at the time that the producer decided to put the gas on the market. MacAvoy's approach is based, in part, on the premise that accounting for contract vintage is in keeping with precedent established in *Hugoton I*. In his report, MacAvoy states that:

> [t]he Court ruled that it is incorrect to determine an RMFP by calculating an average of prices for gas being delivered under long-term agreements signed in previous years but delivered in the year in dispute, stating that because "[To have sold its gas at the wellhead], the plaintiff would have had to enter a contract in one year, and the price fixed in that contract (modified by any escalator provisions therein) would have controlled in each of the subsequent years." Accounting for contract vintage, in estimating an average price, is in keeping with Hugoton I. (quoting *Hugoton I*, 161 Ct.Cl. at 287, 315 F.2d at 876).

MacAvoy takes this statement out of context. This statement was made in response to taxpayer's assertion that to determine the constructive income of raw gas at the wellhead in each tax year in issue, it is necessary to take the price which taxpayer could have obtained under a long-term contract entered in each tax year in question. The *Hugoton* court responded, however, that the taxpayer could not have entered a

new long-term contract for the sale of its gas in each of these years for the reason stated in the language quoted by MacAvoy. Moreover, the court commented in a footnote that:

> Hence it might be suggested that the representative market price be computed solely on the basis of the price which [taxpayer] could have obtained under a long-term contract entered in a single past year in which it would be reasonable to assume he would have entered such a contract. This suggestion has not been offered by either of the parties and, for several reasons, it does not appear a satisfactory alternative.

Hugoton I, 161 Ct.Cl. at 287 n. 28, 315 F.2d at 876 n. 28. The approach discussed in footnote twenty-eight is similar to the vintaging method MacAvoy advocates. The *Hugoton* court remanded the case to the trial commissioner for a determination of RMFP by calculating the weighted average of all contracts in effect each year under which comparable gas was sold rather than merely considering the contracts entered into during a specific tax year. *Hugoton I*, 161 Ct.Cl. at 281, 315 F.2d at 872. MacAvoy's method yields an estimate of the 1974 market price that one would expect to obtain under contracts of the same vintage and terms as the TIC contracts. This is, in effect, a determination of "market value" rather than "representative price." The *Hugoton* court stated:

> It would be consistent with the difference between these terms ["market value" and "market price"] to hold that although the *market value* of gas at the wellhead is the amount that could be obtained for it under a new contract at any given time, the *representative price* is the price which is in

> fact being obtained under all existing comparable contracts.

Hugoton I, 161 Ct.Cl. at 284, 315 F.2d at 874 (emphasis in original).

As noted, the parties dispute whether the RMFP is computed by taking, as Exxon contends, the weighted average price of sales of comparable gas or, as Defendant maintains, the weighted average price of comparable contracts. The *Hugoton* court, in the language quoted above, refers to "comparable contracts." In the second *Hugoton* decision the court states that the RMFP "demands the utilization of an accounting system which considers comparative sales." 172 Ct.Cl. at 459, 349 F.2d at 427. Likewise, the *Panhandle* court makes frequent reference in its discussion of RMFP to "comparable sales of comparable gas." In *Panhandle* the court states that the market comparison method (or RMFP) "naturally entail[s] a study of sales of similar gas at the wellhead by other producers comparably situated." 187 Ct.Cl. at 145, 408 F.2d at 701. In neither case does the court clearly define what makes contracts or sales comparable.

Nonetheless, contrary to MacAvoy's assertions, it it readily apparent from *Hugoton* and *Panhandle* that vintaging of contracts is not required in computing RMFP. Likewise, the presence of price escalation clauses was deemed irrelevant by the *Hugoton* court. The taxpayer in *Hugoton* argued that older contracts without price escalation clauses should not be included in computing RMFP. In rejecting taxpayer's argument, the court stated:

> Contracts entered far in the past and without such clauses will of course tend to reduce the representative price; but we see no basis for con-

> cluding that because particular contracts were unfavorable to the seller they should not be included in the computations.

Hugoton I, 161 Ct.Cl. at 289, 315 F.2d at 877.

Rather than take contracts which could be considered comparable contracts, MacAvoy in essence takes contracts from Ellis' study, which defendant contends in the instant case are not comparable, and attempts to make them comparable to each one of Exxon's seventeen TIC contracts in issue. This is quite different than computing the RMFP by using contracts that are in fact actually comparable, which defendant contends is the correct procedure to follow.

MacAvoy's final method, a simulation exercise used to check the correctness of the first two methods, based on supply and demand curves, yielded a price of $.287 per Mcf. This so-called "back of the envelope" exercise attempted to determine what the highest price Exxon would have received at the wellhead for all its gas if Exxon were freed of its seventeen TIC contracts at the beginning of 1974. This exercise is, in his own words, "of footnote value."

In sum, MacAvoy's approach to computing the RMFP is to find a comparable price to the TIC contracts. The court finds that his conclusion that "[t]he relevant markets in which Exxon competed were those in which contracts were signed at the same time as the TIC contracts," and that "[t]he inclusion of contracts from other years in the comparison sample causes [the RFMP] to be inaccurate" is contrary to Court of Claims precedents. Moreover, as MacAvoy's RMFP of $.25 per Mcf is computed from sales selected from Ellis' database, it likewise, suffers from the same flaws, namely inclusion of non-wellhead sales.

2. Defendant's Net-Back Method

Next, defendant asserts that in the absence of a reasonable RMFP, Exxon should base its depletion deduction on the value derived from a net-back (or proportionate-profits) method. Professor John M. Lacey, defendant's expert in the field of accounting, asserts that $.21 per Mcf is the figure derived from a proper net-back procedure. Lacey is currently an Ernest & Young Research Fellow and Professor of Accounting at California State University, Long Beach. Lacey's computations are based on data provided to him by Exxon and upon data from the parties' stipulations.

The net-back method begins at the points of sale of the products produced from the natural gas. The computation moves backwards, upstream through the delivery, manufacturing, and production processes until it reaches the initial separator (the earliest point at which raw, untreated natural gas can be reliably measured). The resulting net-back value of the gas at the initial separator allegedly represents the most a rational buyer would pay for the gas given the existing contracts and relationships in place. The Court of Claims has recognized that an advantage of the net-back or proportionate profits method is that it is related directly to the taxpayer's own income and allows computation of tax liabiilty by reference only to the taxpayer's books. *Hugoton I*, 161 Ct. Cl. at 282, 315 F.2d at 872-73.

Lacey's net-back computation involved four steps. The first step starts with the actual revenue from the delivery through EGS of residue gas to TIC customers, an internal transfer price for inter-company transfers, and actual revenues for miscellaneous rev-

enues (and some transportation and exchange agreements that are treated as if they were delivered through EGS). From that total is deducted the value of transporting the gas from the EGS inlet to the customers to find the value of the residue gas at the EGS inlet. The second step is to allocate the value of the residue gas at the EGS inlet from step one back to the gas plants from which it came and to a single, aggregate amount for all properties that fed gas into EGS without passing it through a gas plant. The third step is to add to the EGS value allocated back to each gas plant the value associated with the natural gas liquids at that plant and to deduct the gas plant expenses and return to the gas plant for each plant. The result is the value at the inlet to the gas plant. For those properties that fed gas into EGS without passing it through a gas plant this step is unnecessary because no liquid revenue was generated and no gas plant expenses were incurred.

The fourth step allocates the value at the inlet to each gas plant back to the properties that feed into that plant. For those properties that fed gas into EGS without passing it through a gas plant the aggregate amount is allocated back to the individual properties. Also, other revenues (deliveries of gas without passing it through a gas plant to customers other than TIC, lease fuel values, and the value of liquids extracted without a gas plant) are added to the value at the individual property. Royalty paid for each property and transportation and property costs to get the gas from the property to the gas plant or EGS are deducted at the individual property.

Following these steps, Lacey determined that $.21 per Mcf is the value of Exxon's gas at the outlet of

the initial separator. Whereas Lacey's net-back computation represents the value at the effluent of the initial separator for raw, untreated gas produced from each property in issue during 1974, the Commissioner's net-back procedure reflects only the price of the gas sold under each of the seventeen TIC contracts less transportation.

Exxon cites *Panhandle* for the proposition that if any net-back is necessary the court should start with the revenue estimated from the point of sale nearest the wellhead, which in this case, is Ellis' wellhead sales price of $.41 per Mcf. The court disagrees with this contention for two reasons. First, if as Exxon urges, the court were to accept Ellis' $.41 per Mcf as the RMFP for the gas in issue there would be no need to net-back from this figure because it purportedly represents the value of raw unprocessed gas "in the vicinity of the wellhead."

Second, Exxon's reliance on *Panhandle* is misplaced. The *Panhandle* court was faced with the peculiar situation where all the gas in issue was sold for $.325 per Mcf whether sold at the wellhead or sold after it was gathered, transported, and delivered away from the wellhead. The court used $.325 per Mcf as the RMFP for only that portion of the gas that was sold at the wellhead. For the balance of the gas sold, *i.e.*, the gas gathered and transported off the lease, the *Panhandle* court, like the Commissioner in the instant case, performed a net-back. The court net-backed from the sale price of $.325 per Mcf the cost of gathering and transporting the gas away from the wellhead ($.035 per Mcf), reasoning that applying the $.325 per Mcf price to the gas sold away from the wellhead would entitle taxpayer to a depletion allowance on

the amount it received for the gas after transportation and delivery to the purchaser. In other words "$.325 per Mcf was not the amount that [taxpayer] under normal circumstances 'would have received had he sold the gas at the wellhead.' " *See Panhandle*, 187 Ct.Cl. at 171-75, 408 F.2d at 715-18. Thus the *Panhandle* court, net-backed from taxpayer's ultimate sales proceeds from the gas, not from the RMFP.

Next, Exxon contends that Lacey's net-back method is flawed because it is arbitrary and result-oriented; instead of using data provided by Exxon, Lacey used only some of the data and substituted his own estimates in an effort to achieve a lower net-back amount. Lacey, Exxon argues, "mixed and matched" a variety of figures in order to reach a pre-ordained conclusion that the RMFP was less than what Exxon claimed.

For example, Exxon asserts that Lacey ignored the $.35 per Mcf price that Exxon used to value intercompany transfers of residue gas to its Baytown Refinery and used "his own" $.23 Mcf figure and that this change reduced Exxon's actual proceeds by approximately $9 million. The $.23 per Mcf price that Lacey used was not, as Exxon asserts, his opinion of market value; instead the $.23 per Mcf price reflects Exxon's actual revenue from the TIC contracts. Lacey used $.23 per Mcf because Exxon's intracompany transfer price of $.35 per Mcf was not representative of the contracts and relationships in place during 1974. Exxon did not buy gas at $.35 per Mcf and then sell it at $.23 per Mcf. Exxon did not, in fact, buy the gas, it was produced from the properties in issue. Rather than use internal transfer prices that were not representative of the contracts and commitments in place, Lacey substituted figures that were repre-

sentative. Exxon's remaining challenges to Lacey's net-back method are likewise without merit.

The court considers Lacey's $.21 per Mcf price to be a reasonable net-back price, comparable to the Commissioner's net-back price of $.212 per Mcf. While Lacey's method is a more complete approach to the net-back, the Commissioner's approach in this case has been accepted as a reasonable method to calculate gross income for depletion allowance in the absence of an RMFP. *See Panhandle*, 187 Ct.Cl. at 173-75, 408 F.2d at 717-18.

C. Reasonableness of an RMFP of $.41 per Mcf

Assuming, for arguments sake, that Exxon has established an RMFP of $.41 per Mcf, the burden remains on Exxon to prove that that price can be "reasonably and realistically considered *representative* of [Exxon's] economic situation or a 'representative market or field price' in any real sense of such term." *Panhandle*, 187 Ct.Cl. at 171, 408 F.2d at 716 (emphasis in original). As noted earlier, deductions are a matter of legislative grace, not of right. *New Colonial Ice Co. v. Helvering*, 292 U.S. 435, 440 (1934). Pursuant to the Code, Exxon "shall be allowed as a deduction in computing taxable income a *reasonable allowance for depletion* . . . according to the peculiar conditions in each case." I.R.C. § 611(a) (emphasis added). Therefore, the court must decide whether a depletion allowance based on an RMFP in excess of Exxon's actual income from the gas in issue, is reasonable according to the facts of this case.

Exxon asserts that the RMFP of $.41 per Mcf is reasonable because that price accurately reflects 1974 market conditions, and it is representative of the

amount for which Exxon could have sold its gas at the wellhead under a fair selection of the wellhead sales contracts in existence. However, as indicated previously, market conditions for natural gas in Texas during 1974 did not reflect normal circumstances. Indeed, the price of natural gas varied greatly and the market was volatile. *See infra* note 28.

In the instant case, Exxon committed most of the gas in issue under seventeen TIC contracts, Exxon, presumably, entred into these contracts because it was advantageous for it do so at that time. Indeed, the evidence shows that Exxon received better than market value for the TIC contracts at the time it entered into the contracts. It is reasonable to assume that Exxon could not have sold the gas in issue for the price of $.41 per Mcf in 1974 because most of it was committed to the TIC contract customers and to internal users. Exxon did not have any other reserves of gas available to fulfill its commitments if it had attempted to sell the gas in 1974.[26]

Another factor bearing on the reasonableness of an RMFP of $.41 per Mcf is Exxon's own volume weighted average price for sales purportedly made in the immediate vicinity of the well, which appear in the record as part of Ellis' database of 2,228 trans-

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[26] Defendant, as discussed earlier, used MacAvoy's "back of the envelope" method to demonstrate the effect an increase in supply, in relation to demand, has on price. It is conceivable that, in 1974, any increase in supply caused by releasing Exxon from its commitments, and the subsequent sale of the gas from the TIC contracts on the open market, would have resulted in a price lower than $.41 per Mcf. There is some merit to this observation in that, it serves to counter the observation by Exxon that it could have sold its gas, if it was not committed to the TIC contracts, at a price in excess of $.41 per Mcf.

actions. Ellis' sample includes forty-six sales made by Exxon to various purchasers which were not restricted by any prior contract commitment. The volume weighted average for both interstate and intrastate Accounts 800 and 801 transactions was $.28 per Mcf. Limiting the calculation to Account 800 transactions (wellhead sales) yields a volume weighted average price of $.25 per Mcf. This analysis casts a shadow on the reasonableness of $.41 per Mcf as an RMFP.

Exxon also claims that the RMFP of $.41 per Mcf places it in the same situation as the average non-integrated producer selling gas in the relevant market area during 1974. This result, claims Exxon, is consistent with the rationale for the RMFP rule, *i.e.*, to place integrated taxpayers on a par with non-integrated, independent producers in their allowable depletion deductions, *Cannelton*, 364 U.S. at 89; *Henderson*, 324 F.2d at 15; *Panhandle*, 187 Ct.Cl. at 143-44, 408 F.2d at 700. Exxon's statement of the congressional objective in allowing depletion deductions is correct. The effect of this rule, as discussed earlier, is to limit "constructive income" to the value of the raw product rather than the finished article's value. *Panhandle*, 187 Ct.Cl. at 144, 408 F.2d at 700.

Contrary to Exxon's claim, allowing Exxon to use the RMFP of $.41 per Mcf does not place Exxon on par with non-integrated producers. Permitting Exxon to base its depletion deduction on an RMFP in excess of its actual income would in fact give Exxon an unfair competitive advantage over non-integrated producers. It is true that because $.41 per Mcf is an average, some non-integrated producers' depletion allowance per Mcf are greater than $.41, and some are less than $.41. The relevant point, however, is that

each non-integrated producer must base its depletion allowance on its *actual income*. The advantage Exxon would gain by applying the RMFP of $.41 per Mcf, is a depletion allowance of approximately $155,000,000 in excess of its actual income. That result does not place Exxon on par with non-integrated producers; it places Exxon in a position superior to non-integrated producers. It is an "indigestable" result, contrary to the legislative history of and purposes for the depletion deduction.[27] Therefore, the court concludes that in this case, an RMFP of $.41 per Mcf is not a reasonable basis for Exxon's depletion deduction for 1974.[28]

IV

For the foregoing reasons, the court holds that Exxon is not entitled to a refund of federal income

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[27] Exxon contends that the Tax Court, in rejecting Exxon's 1979 RMFP as "indigestible," erred in comparing that RMFP to Exxon's sales proceeds under the TIC contracts. *See Exxon*, 102 T.C. at 723, 736-37, 739-40, 743-44. The Tax Court, Exxon argues, punished Exxon which was unable, because of its integrated operations, to increase its sales prices in a rising market. In the instant case, the evidence shows that Exxon's commitments under the seventeen TIC contracts, not its integrated operations, precluded Exxon from selling the gas in issue.

[28] Furthermore, it is unreasonable to assume that Exxon would have sold its gas at the wellhead at a price of $.41 per Mcf under "normal circumstances." *See Panhandle*, 187 Ct.Cl. at 172, 408 F.2d at 716 (observing that under normal circumstances, a producer would not sell gas at the wellhead for the same price at which it sells gas that it gathers, transports, and delivers away from the wellhead). Gas in 1974 was not sold under normal circumstances. The volatility of the market was reflected by the rapid escalation of prices. Moreover, it is not a normal situation when something is produced at a "constructive" price in excess of its selling price.

taxes paid for the tax year ending December 31, 1974. As the court stated earlier, "there is a *strong* rebuttable presumption of the correctness of the determination of the Commissioner." *Mullholland*, 28 Fed. Cl. at 331. Exxon has not met its burden of proving that the Commissioner's action was arbitrary, capricius, or unreasonable. The court is not persuaded that the RMFP of $.41 per Mcf was calculated from a "fair selection of contracts." Furthermore, the court concludes, that based upon the "peculiar conditions" of this case an RMFP in excess of Exxon's actual income cannot be "reasonably and realistically considered *representative* of [Exxon's] economic situation or a 'representative market or field price' in any real sense of such term." *Panhandle*, 187 Ct.Cl. at 171, 408 F.2d at 716 (emphasis in original). While a number of factors contributed to the rapid increase in the price of gas in 1974, *e.g.*, the OPEC oil embargo and the increase in the refinery and petrochemical industry, the court cannot conclude that these factors are compelling justification to allow a depletion deduction on a constructive income greatly in excess of Exxon's actual income.

Accordingly, the Clerk is directed to enter judgment dismissing the complaint. No costs.

/s/ Thomas J. Lydon
THOMAS J. LYDON
Senior Judge

APPENDIX D

UNITED STATES COURT OF APPEALS
FOR THE FEDERAL COURT

95-5116

EXXON CORPORATION and SUBSIDIARIES,
PLAINTIFFS-APPELLANTS

v.

THE UNITED STATES,
DEFENDANT-APPELLEE

ORDER

A combined petition for rehearing and suggestion for rehearing in banc having been filed by the APPELLEE, and a response thereto having been invited by the court and filed by the APPELLANT, and the petition for rehearing having been referred to the panel that heard the appeal, and thereafter the suggestion for rehearing in banc and response having been referred to the circuit judges who are in regular active service,

UPON CONSIDERATION THEREOF, it is

ORDERED that the petition for rehearing be, and the same hereby is, DENIED and it is further

ORDEDED that the suggestion for rehearing in banc be, and the same hereby is, DECLINED.

The mandate of the court will issue on September 24, 1996.

Chief Judge ARCHER, Circuit Judge RICH and Circuit Judge SCHALL did not participate in the vote.

FOR THE COURT
FRANCIS X. GINDHART
Clerk

Dated: September 17, 1996

By /s/ Brian P. LeDuc
BRIAN P. LEDUC
Associate Chief Deputy Clerk

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